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State Corporation Commission
Kansas

Docket No. 12-MKEE-380-RTS

In the Matter of the Application of)
Mid-Kansas Electric Company, LLC)
For Approval to Make Certain Changes)
In its Charges for Electric Service in the)
Geographic Service Territory Served by)
Southern Pioneer Electric Company.)

2012.04.20 13:07:22
Kansas Corporation Commission
/s/ Patrice Petersen-Klein

REDACTED DIRECT

STAFF TESTIMONY

PREPARED BY

LAURA BOWMAN

UTILITIES DIVISION

KANSAS CORPORATION COMMISSION

(** ████████ Denotes Confidential Information **)

1 **Q. Would you please state your name?**

2 A. My name is Laura K. Bowman

3

4 **Q. What is your business address?**

5 A. My business address is the Kansas Corporation Commission, 1500 Southwest
6 Arrowhead Road, Topeka, Kansas, 66604.

7

8 **Q. By whom are you employed and in what capacity?**

9 A. I am employed by the Kansas Corporation Commission (KCC or Commission) as
10 a Managing Auditor.

11

12 **Q. Would you please describe your educational background and business
13 experience?**

14 A. I received a Bachelor's of Science in Business Administration with an emphasis
15 in Accounting from Missouri Western State University in May of 2005. I joined
16 the Commission as an Auditor in August 2006 and in June 2008 I was promoted
17 to Senior Auditor. I left the Commission in May of 2010 and in November 2010 I
18 returned to the Commission in my current position.

19

20 **Q. Have you ever testified before the Commission?**

21 A. Yes. I have filed testimony in several dockets before the Commission.

22

1 **Q. What were your responsibilities in the review of Mid-Kansas Electric**
2 **Company's divisional rate case filing for a change in rates for the service**
3 **territory of Southern Pioneer Electric Company (Southern Pioneer or**
4 **Applicant) rate case Application in Docket No. 12-MKKEE-380-RTS, which**
5 **was filed on December 20, 2011?**

6 A. My responsibilities as the auditor-in-charge were to analyze, audit, and review
7 Southern Pioneer's rate case Application. In addition, I calculated and am
8 sponsoring selected Staff adjustments to Southern Pioneer's Pro Forma Income
9 Statement. My duties were carried out under the direction of the Director of
10 Utilities, Jeff McClanahan.

11 I am sponsoring the following Pro Forma Adjustments to Southern Pioneer's
12 income statement:

13 <u>Adjustment No.</u>	<u>Description</u>
14 Adjustment No. 4	LAC revenues
15 Adjustment No. 5	Income Taxes
16 Adjustment No. 6	Acquisition Premium
17 Adjustment No. 7	Bad Debt Expense

18 In addition to the income statement adjustments listed above, I am also discussing
19 the Debt Service Coverage (DSC) Ratemaking Plan as proposed by Southern
20 Pioneer.

21
22 **Q. Please provide the list of other Staff witnesses and a brief description of the**
23 **testimony they are sponsoring.**

1 A. Kristina Luke: Ms. Luke will sponsor testimony related to various income
2 statement adjustments proposed by Staff and is sponsoring Staff's schedules.

3 Andria Finger: Ms. Finger will sponsor testimony related to various income
4 statement adjustments proposed by Staff.

5 Adam Gatewood: Mr. Gatewood will sponsor testimony related to Southern
6 Pioneer's Rural Utility Service (RUS) buyout payment.

7 Robert Glass: Mr. Glass will sponsor testimony related to Staff's rate design.

8 Elena Larson: Ms. Larson will sponsor testimony related to Staff's class cost of
9 service.

10

11 **Q. Were the adjustments you are sponsoring prepared by you or under your**
12 **supervision based upon your examination of Southern Pioneer's books and**
13 **records?**

14 A. Yes, they were.

15

16 **Q. Please provide a summary of your testimony.**

17 A. The following is a summary of Staff's adjustments I am sponsoring:

- 18 • Staff recommends a revenue increase of \$2,879,566;
- 19 • Staff recommends disallowance of the proposed DSC Ratemaking Plan;
- 20 • Staff recommends approval of several income statement adjustments;
- 21 • Staff recommends approval of Staff's Local Access Charge (LAC) revenues
22 calculation.

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BACKGROUND

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Q. Please provide an overview of MKEC and Southern Pioneer

A. Mid-Kansas is a limited liability company, whom is owned by five Kansas consumer-owned cooperatives and one subsidiary of a consumer-owned cooperative. MKEC was organized for the purpose of acquiring and operating the former Aquila-WPK electric utility business and operations. The five member cooperatives are: (1) Lane-Scott Electric Cooperative, Inc.; (2) Prairie Land Electric Cooperative Association, Inc.; (3) Victory Electric Cooperative Association, Inc.; (4) Western Cooperative Electric Association, Inc.; (5) and Wheatland Electric Cooperative, Inc. Southern Pioneer is the only member who is not a consumer-owned cooperative.

Q. How is Southern Pioneer organized, since they are not a consumer-owned cooperative?

A. Southern Pioneer is formed as a C-Corporation; however, they have agreed to operate as any other consumer-owned cooperative in that they will not remit dividends to its sole shareholder, Pioneer Electric without KCC and lender approvals. Since they operate as a cooperative, their revenue requirement model is similar to the other five cooperative revenue requirement model(s) in that they calculate a DSC or Times Interest Earned Ratio (TIER) just as a consumer-owned cooperative would to ensure financial viability. However, the main difference

1 exists in the fact that Southern Pioneer is still responsible for paying income taxes
2 as they are a C-Corporation and not a not-for-profit cooperative.

3

4 **Q. Please provide an overview of the rate case request as filed by Southern**
5 **Pioneer?**

6 A. Southern Pioneer has requested to recover rates through a Debt Service Coverage
7 (DSC) ratemaking approach for Mid-Kansas' services provided to customers
8 within its designated geographical certificated service territory served by
9 Southern Pioneer. Under this approach, Southern Pioneer is requesting approval
10 of a DSC ratemaking plan that would provide an initial rate increase of
11 \$6,112,948 or 10.5 percent. This proposal would allocate \$5,871,021 to retail
12 customers and \$241,927 to the LAC customers. The LAC portion is revenue paid
13 by third-party users of Southern Pioneer's 34.5 kV facilities. Southern Pioneer's
14 request is based on an initial DSC ratio of 1.8, with an annual increase in the
15 target ratio over a five year period.

16

17 **Q. What is Southern Pioneer's proposed revenue requirement, if the DSC**
18 **Ratemaking Plan is not approved by the Commission?**

19 A. Southern Pioneer has requested a rate increase of \$7,992,522 or 13.7 percent
20 using a DSC ratio of 2.0. This proposal would allocate \$7,620,031 to retail
21 customers and \$372,491 to the LAC customers.

22

1 **Q. What test year did Southern Pioneer use in its Application before the**
2 **Commission?**

3 A. Southern Pioneer used a test year ending December 31, 2010, with pro forma
4 adjustments through May 31, 2011.

5

6 **Q. What are the results of Staff's revenue requirement analysis?**

7 A. Staff recommends that Southern Pioneer be granted a revenue requirement
8 increase of \$2,879,556 for its retail customers and \$173,463 in LAC revenue from
9 third-party users of the 34.5 kV facilities. Staff's revenue requirement is based on
10 pro forma adjusted operating expense of \$54,313,857, and long-term interest and
11 margin requirements of \$9,604,109, for a total revenue requirement of
12 \$62,026,492 (inclusive of other operating revenue and LAC revenue). Staff
13 updated many areas of the income statement based on known and measurable
14 changes that have occurred during the calendar year 2011. Staff's revenue
15 requirement calculation is based on a DSC ratio of 2.0, and pro forma annualized
16 interest expense and principle payments of \$4,547,758 and \$1,195,846
17 respectively.

18

19

JUST AND REASONABLE REVIEW

20

21 **Q. Does Staff believe that the results of Staff's revenue requirement analysis**
22 **results in just and reasonable rates?**

1 A. Yes. The result of Staff's revenue requirement analysis meets the balancing test
2 set forth by the Kansas Supreme Court, which stated:

3 The leading cases in this clearly indicate that the goal should be a rate fixed
4 within the 'zone of reasonableness' after the application of a balancing test in
5 which the interests of all concerned parties are considered. In rate-making cases,
6 the parties whose interests must be considered and balanced are these: (1) the
7 utility's investors vs. the ratepayers; (2) the present ratepayers vs. the future
8 ratepayers; and (3) the public interest.¹
9

10 **Investors vs. ratepayers** – each Staff adjustment presented below is presented
11 with the intention of producing a revenue requirement that reflects Southern
12 Pioneer's ongoing, normalized operations. This approach affords Southern
13 Pioneer (and its investor) the opportunity to earn its authorized margin, but not a
14 guarantee. Also, Staff removed various expenses from the cost of service we
15 contend would be inappropriate to recover from Southern Pioneer's ratepayers.
16 Additionally, if Staff identified mistakes in Southern Pioneer's calculations, Staff
17 has made corrections, whether the result was an increase or a decrease in the
18 revenue requirement.

19 **Current ratepayers vs. future ratepayers** – where possible, Staff attempted to
20 identify any intergenerational issues (such as reclassifying outside services to
21 property plant and equipment (PPE), in order to allow those costs to be recovered
22 over the life of the project, instead of one year) and is making recommendations
23 that are appropriately balanced between present and future ratepayers.

24 **Public Interest Generally** – generally speaking, the public interest is served
25 when ratepayers' interests are carefully considered and protected. This process
26 includes protecting ratepayers from unreasonably high prices, discriminatory

¹ Kan. Gas and Electric Co. v. State Corp Comm'n, 239 Kan. 483, 488 (1986).

1 prices, and/or unreliable service. This also includes assuring that rates are not so
2 low that the utilities that serve those ratepayers are unable to provide reliable
3 service, remain financially stable, and attract capital on reasonable terms. Staff
4 carefully considered the public interest in developing the recommendations
5 presented in this Docket, and feels that the public interest will be served if the
6 Commission adopts Staff's recommendations.

7

8 **Q. What accounts for the differences between Staff's and Southern Pioneer's**
9 **recommended revenue requirement?**

10 A. Listed below is a table of each Staff adjustment, and the Staff witness sponsoring
11 each adjustment. Although the particulars of each adjustment are different,
12 Staff's adjustments are usually made in order to (1) correct an error presented by
13 the Applicant (2) revise a pro forma adjustment to utilize more current known and
14 measurable data; and (3) remove expenses that would not be appropriate to
15 recover from ratepayers.

16 Each of the adjustments listed below is made with the intention that the end
17 result is a revenue requirement that is in the public interest and results in just and
18 reasonable rates for all stakeholders involved.

19

20

Adj. No.	Witness	Description	Adjustment
IS-1	Kristina Luke	Advertising	(11,238)
IS-2	Kristina Luke	Payroll	(547,168)

IS-3	Kristina Luke	Benefits	(223,924)
IS-4	Laura Bowman	Local Access Charge Revenues	173,463
IS-5	Laura Bowman	Income Taxes	(1,054,289)
IS-6	Laura Bowman	Acquisition Premium	785,459
IS-7	Andria Finger	Bad Debt Expense	(2,168)
IS-8	Andria Finger	Depreciation	43,274
IS-9	Andria Finger	Dues and Lobbying	(7,902)
IS-10	Andria Finger	Donations	(19,656)
IS-11	Andria Finger	Entertainment & Spousal Travel	(6,950)
IS-12	Andria Finger	Penalties & Fines	(850)
IS-13	Andria Finger	Outside Services	(1,737)
IS-14	Andria Finger	Rate Case Expense	40,315

1

2

TIER AND DSC RATIO

3

4 **Q. Please define the DSC ratio and the TIER ratio, and discuss the differences**
5 **between the two.**

6 A. The DSC Ratio, or Debt Service Coverage Ratio, is calculated as follows:

7
$$\frac{(\text{Net Margins} + \text{Interest Expense on Long-Term Debt} + \text{Depreciation \& Amortization})}{(\text{Interest on Long-Term Debt} + \text{Principle on Long-Term Debt})}$$

8

9

10 The TIER ratio, or Times Interest Earned Ratio, is calculated as follows:

11
$$\frac{(\text{Net Margin} + \text{Interest on Long-Term Debt})}{\text{Interest on Long-Term Debt}}$$

12

1 Both DSC and TIER ratios have been used by Staff, utilities, lenders, and the
2 Commission to assess the financial viability of a utility and the likelihood that the
3 utility will be able to service its debt payments in a timely fashion. The TIER
4 ratio relies on income, as a multiple of interest payments to make its assessment.
5 The numerator of the DSC ratio is a rough substitute for cash flow, and the
6 denominator includes principle payments on debt as well as interest expense,
7 making it a more encompassing view of the ability of a utility to meet its fixed
8 obligations related to its debt.

9

10 **Q. Why did Staff choose to calculate its revenue requirement using a DSC ratio**
11 **instead of a TIER ratio?**

12 A. Staff chose to base its revenue requirement on the DSC ratio because it most
13 closely matches the CoBank loan covenants currently applicable to all of
14 Southern Pioneer's long term debt. In October of 2011, Southern Pioneer
15 refinanced all of its long-term debt with CoBank and as a result has
16 approximately \$90,441,809 of outstanding long-term debt as of December 31,
17 2011.² All of this debt was issued by CoBank, and all of the debt is subject to a
18 minimum DSC ratio of 1.35 for a twelve month period ending December 31, 2012
19 and each fiscal quarter thereafter. Because Staff's revenue requirement is based
20 on a DSC, the Commission should have greater certainty that Staff's revenue
21 requirement is calculated in a fashion that will allow Southern Pioneer to make

² In October of 2011, Southern Pioneer refinanced all of its Rural Utility Services (RUS) debt that was held with Federal Finance Bank (FFB) with CoBank. As a result of this refinance, Southern Pioneer was required to pay a penalty fee to RUS for early buyout of the loan. The outstanding principle balance of \$90 million shown above includes a prepayment premium principle balance of \$9,686,403.

1 timely payments on its debt service and meet or exceed its lender's loan
2 covenants, while limiting unnecessary rate increases. Because a revenue
3 requirement calculation can differ dramatically between the two approaches,
4 Staff's position is that the Commission should utilize the financial ratio (TIER or
5 DSC) that most closely aligns with Southern Pioneer's loan covenants.

6

7 **Q. Does Southern Pioneer's loan covenants allow for the calculation of a DSC?**

8 A. Yes. Page 19 of Southern Pioneer's loan covenants states:³

9 "8.1 Debt Service Coverage Ratio. The Company (on both a consolidated and
10 an unconsolidated basis) will have at the end of each fiscal quarter of the
11 Company, a Debt Service Coverage Ratio for the twelve month period ending
12 with the end of such quarter of not less than 1.35 to 1.0"

13

14 **Q. Did Southern Pioneer calculate its revenue requirement on a DSC basis?**

15 A. Yes. Southern Pioneer calculated its proposed revenue requirement(s) with an O-
16 DSC ratio. Exhibit A-2 of the CoBank loan covenants states:

17 "Debt Service Coverage Ratio" shall mean the ratio of: (1) the difference
18 between (i) net income (after taxes and after eliminating any gain or loss on
19 sale of assets or other extraordinary gain or loss), plus depreciation expense,
20 amortization expense, and interest expense; minus (ii) non-cash patronage and
21 non-cash income from joint ventures; to (2) all principle payments due within
22 the period on all Long-Term Debt plus interest expense (all as calculated for
23 the twelve month period ending with the end of the quarter in which the
24 calculation is being made in accordance with GAAP consistently applied)."
25

26 **Q. If the loan covenants provide a calculation for an O-DSC ratio, then why is**
27 **Staff using the traditional DSC approach?**

³ See Exhibit LKB-6 for a copy of Southern Pioneer's Response to CURB Data Request No. 12.

1 A. Staff's calculation of DSC includes the non-operating margins that appear on the
2 income statement below the operating margin. Staff's method provides a more
3 encompassing view of the company's financial health and its ability to service its
4 debt. Additionally, Staff's DSC calculation is consistent with past cases that have
5 relied on a traditional DSC ratio.

6

7 **Q. You mentioned above that Staff's DSC ratio does not include non-operating**
8 **margins, what does this consist of?**

9 A. The non-operating margins consist of Income from Equity Investments which is
10 Southern Pioneer's share of the income reported on MKEC's Schedule K-1. This
11 income is considered non-cash as Southern Pioneer does not actually receive cash
12 from MKEC. Southern Pioneer also has other non-cash income which relates to
13 the amortization of the acquisition premium and capital credits.

14

15 **Q. Has Staff used the traditional DSC ratio methodology to set a cooperative**
16 **utility's revenue requirement in the past?**

17 A. Yes. Staff calculated the revenue requirement using a traditional DSC ratio in the
18 Kansas Electric Power Cooperative (KEPCO) case, Docket No. 08-KEPE-597-
19 RTS and in the MKEC Wheatland case, Docket No. 11-MKEE-539-RTS. In both
20 cases Staff calculated the DSC ratio which incorporated non-operating margins.

21

22 **Q. Does Staff routinely calculate both a DSC and TIER ratio when reviewing a**
23 **rate case filing?**

1 A. Yes. Staff routinely calculates both DSC and TIER when reviewing the financial
2 position of cooperative utilities, with close attention paid to whether the resulting
3 ratios are sufficient to allow the utility to meet its minimum loan covenants. In
4 this case, there is no minimum TIER requirement on Southern Pioneer's loans.
5 Therefore, while Staff has calculated TIER for information purposes in this case,
6 we do not recommend that the Commission base its revenue requirement
7 calculation on TIER.

8

9 **Q. If Southern Pioneer's loan covenants stipulate a minimum DSC coverage**
10 **ratio of 1.35, then why is Staff recommending a DSC target level of 2.0?**

11 A. Staff chose its DSC level in an attempt to provide Southern Pioneer an adequate
12 cushion of margin that would allow the cooperative to withstand annual
13 fluctuations in operating conditions, while at the same time being supportive of
14 Southern Pioneer's goal to increase the equity levels in its balance sheet. Staff
15 supports the goal to increase equity reserves in this case because Southern Pioneer
16 has very low (negative) equity. A utility with very low levels of equity has higher
17 financial risk than well capitalized utilities, and is less able to withstand adverse
18 shocks or fluctuations in its operations. An increased amount of equity on the
19 balance sheet corresponds to a decreasing amount of financial risk, which should
20 aid the utility's access to low cost capital in the future. Also, a strong balance
21 sheet gives the utility more operating flexibility and helps to protect against
22 unanticipated changes in operations, weather, economic conditions, etc.

23

1 **Q. How does Staff's recommended DSC level of 2.0 compare to the DSC levels**
2 **earned by other distribution cooperatives in the State over the last five**
3 **years?**

4 A. According to the CFC's 2010 Key Ratio Trend Analysis,⁴ the DSC levels earned
5 by distribution cooperatives in the State of Kansas were as follows:

Year	DSC Earned
2006	2.0
2007	2.12
2008	2.08
2009	2.09
2010	2.26

6
7 Staff's recommended 2.0 DSC ratio compares favorably with these earned levels,
8 as the average over this five-year period is 2.11. That makes Staff's
9 recommended DSC level 5.2% less than the five-year average earned DSC.

10

11 **Q. If Staff were to recommend calculating Southern Pioneer's revenue**
12 **requirement based on the O-DSC ratio, would Staff continue to recommend**
13 **a target level of 2.0?**

14 A. While Staff has not fully discussed what the target level would be under the O-
15 DSC methodology; it is unlikely Staff would recommend a 2.0 target level. As
16 shown in the following table, the median O-DSC ratios are lower than the

⁴ National Rural Utilities Cooperative Finance Corporation (CFC) provides an annual Key Ratio Trend Analysis for the nations electric cooperatives. See Exhibit LKB-7 for a copy of the most recent analysis that was provided to Pioneer Electric Cooperative, Inc.

1 traditional DSC ratios. As a result, it would only seem reasonable to lower the
2 target level to coincide with Southern Pioneer's ratio used.

3

Year	O-DSC Ratio
2006	2.12
2007	2.04
2008	1.90
2009	1.99
2010	1.90

4

5

DSC RATEMAKING PLAN

6

7 **Q. Please begin your discussion of Southern Pioneer's DSC Ratemaking**

8 **Approach proposal.**

9 A. Southern Pioneer has proposed to implement a formula ratemaking plan which
10 would allow the Company to change their retail and local access charge rates on
11 an annual basis. This formula plan would increase the authorized revenue
12 requirement to ensure that Southern Pioneer earned the authorized DSC ratio.

13 The following table provides the proposed DSC ratio, by year:

14

15

16

17

Year	Proposed DSC Ratio
2013	1.8
2014	1.9
2015	2.0
2016	2.0

1

2

3 **Q. Has the proposed DSC Ratemaking Plan been used with the KCC or other**
4 **State Commissions?**

5 A. Staff is not aware of any Companies in the State of Kansas that have been
6 authorized use of a formula ratemaking plan similar to the proposal. Southern
7 Pioneer did provide an Order from the Michigan Public Service Commission,
8 which authorized the use of a formula ratemaking plan.⁵ In reviewing the
9 Michigan Commission's order, it became apparent that the Company receiving
10 the formula plan was in dire need of financial assistance. As a result, the
11 Michigan Public Service Commission authorized the Company to increase its
12 rates on an annual basis to allow for timely recovery of revenue increases and to
13 reduce regulatory lag.

14

15 **Q. Does Staff believe the proposal is appropriate for Southern Pioneer?**

16 A. No. Southern Pioneer is not in financial distress and therefore does not need an
17 immediate increase in revenues on an annual basis. In fact, in Southern Pioneer's

⁵ See Exhibit LKB-6 for Southern Pioneer's Response to KEPCO Data Request No. 1-26.

1 annual filing of its TIER and DSC Calculation Analysis, the company indicated
2 the following financial ratios based on the current year's operating margins:

3

Year	TIER	DSC
2009	0.88	1.76
2010	1.62	2.23
2011	1.65	1.72

4

5 As shown above, it is apparent Southern Pioneer is not in a dire financial health
6 and therefore it is not necessary to grant an annual increase in rates.

7

8 **Q. Are there any other reasons for which Staff has based its recommendation on**
9 **the disallowance of the DSC Ratemaking Plan?**

10 A. Yes. Staff is also requesting the Commission disallow the DSC Ratemaking Plan
11 for the following reasons:

12 • As discussed in Docket No. 06-MKEE-524-ACQ (524 Docket), Southern
13 Pioneer had the opportunity to organize itself as a cooperative. If Southern
14 Pioneer had been organized as a cooperative, the Company would be eligible
15 for deregulation as soon as the MKEC spin down is complete. Since Southern
16 Pioneer has forgone this opportunity, it does not seem appropriate to allow
17 them the special treatment that would be received through the formula rate
18 plan.

1 • If the formula ratemaking plan was approved, the Commission would have
2 little to no ability to analyze the costs incurred by Southern Pioneer, as there
3 would be little ability to fully audit and review the revenues and costs
4 included in the calculation of the revenue requirement. Additionally, all
5 incentive to control costs and manage risks would be diminished as Southern
6 Pioneer would have the incentive to increase expenses to ensure the DSC ratio
7 remained at a favorable level.

8 • Staff believes that if Southern Pioneer were to receive the formula ratemaking
9 plan, the desire to roll Southern Pioneer into Pioneer would be mitigated.
10 This is due to the fact that the formula ratemaking plan would be loosely
11 regulated, with little oversight from the Commission (i.e. deregulated in a
12 sense). Southern Pioneer chose to organize the Company as a C-Corp and
13 therefore they should not receive a favorable ratemaking treatment that would
14 allow them to act as if they were a deregulated cooperative.

15

16

INCOME STATEMENT ADJUSTMENTS

17

18 **Q. Please begin by discussing Staff's Adjustment No. 4 to the income statement.**

19 **A.** Staff Adjustment No. 4 (IS-4) increases Southern Pioneer's LAC revenue
20 attributable to third-party users of the 34.5 kV facilities by \$173,463 for a total
21 revenue credit included of \$953,006. This compares to the total revenue credit of
22 \$1,021,470 included in Southern Pioneer's Application. Staff's calculation of the
23 LAC for the 34.5 kV facilities owned by Southern Pioneer is detailed in Staff

1 Exhibit LKB-1 through LKB-1(e). Each of these exhibits is described below.
2 Staff's LAC calculation is essentially the same methodology as Southern
3 Pioneer's and is synchronized with all the other aspects of Staff's revenue
4 requirement analysis. The two differences between Staff's LAC calculation and
5 Southern Pioneer's relate to the reflection of taxes and the amount of margin
6 included in the calculation of the LAC factor. The difference in the amount of
7 margin included in the LAC is a result of the different DSC methodologies used
8 in calculating the overall revenue requirement.

9
10 **Q. Please provide a description of the Staff exhibits used to calculate the LAC**
11 **for Southern Pioneer's 34.5 kV facilities.**

12 A. Staff's LAC exhibits are described below:

- 13 • Exhibit LKB-1: This is the input page used to input the different elements of
14 the LAC cost of service from Staff's revenue requirement. Staff's updated
15 plant, operating expense, and payroll values are listed here, as well as the Staff
16 reference where the numbers were derived.
- 17 • Exhibit LKB-1 (a): Staff's calculation of the LAC revenue requirement, as
18 well as the source for each of the components that are needed to perform the
19 calculation.
- 20 • Exhibit LKB-1 (b): Staff's calculation of the labor and net allocation factors
21 that are used throughout the LAC revenue requirement calculation.
- 22 • Exhibit LKB-1 (c): Staff's calculation of the depreciation expense used in the
23 LAC revenue requirement.

- 1 • Exhibit LKB-1 (d): Staff's calculation of the third-party revenue credit
2 associated with the use of the 34.5 kV facilities.
- 3 • Exhibit LKB-1 (e): Staff's calculation of the total billing determinants for the
4 local access system for the year ended December 31, 2010. These billing
5 determinants are used to determine the overall LAC charge, and to calculate
6 the third-party revenue credit associated with third-party use of the local
7 access system.

8

9 **Q. Did Staff update or modify any of the exhibits listed above for purposes of**
10 **calculating the LAC?**

11 A. Yes. Staff updated Exhibit LKB-1 (e) to correct for two errors. First, a formula
12 error existed on the 2010 Hour Loads spreadsheet, which is used to support the
13 LAC billing demand.⁶ Second, to properly state the billing demand for the
14 Greensburg Wind Farm (GWF), Staff requested that Southern Pioneer re-calculate
15 the 2010 billing demand for GWF assuming the demand was calculated at the
16 coincident peak (CP). This re-calculation was necessary as GWF on a going
17 forward basis will no longer be billed the reservation.⁷

18 Staff also updated Exhibit LKB-1 (a) to remove the proposed change in
19 Southern Pioneer's income tax requirement. As discussed in greater detail in
20 Staff Adjustment IS-5, Staff is excluding all income tax calculation from Southern

⁶ See Exhibit 6 for Southern Pioneer's response to Staff Data Request No. 198.

⁷ The change in the way GWF's demand is calculated is in accordance with the Commission Order dated January 11, 2012, in Docket No. 11-GIME-597-GIE. Prior to this Commission Order, GWF was billed based on a reservation of 12,000 kW as outlined in Docket No. 09-MKEE-969-RTS.

1 Pioneer's revenue requirement. As a result, it is only appropriate to remove
2 income taxes from the calculation of the LAC.

3

4 **Q. Please discuss Staff's Adjustment No. 5 to the income statement.**

5 A. Staff Adjustment No. 5 (IS-5) decreases Southern Pioneer's operating expenses
6 by \$1,054,289.⁸ Staff's adjustment removes the deferred income tax expense
7 recorded on Southern Pioneer's books. Staff does not believe Southern Pioneer's
8 revenue requirement should include the deferred tax expense as they are not
9 expected to pay income taxes for many years to come. As of December 31, 2010,
10 Southern Pioneer had a federal net operating loss carry forward balance of
11 [REDACTED]⁹ that can be used to offset taxable income until the year 2029.
12 Additionally, Southern Pioneer has [REDACTED] of Kansas net operating loss
13 that can be carried forward until 2019. This makes it very unlikely that Southern
14 Pioneer will pay any income tax to the state or federal government between now
15 and their next rate case.

16

17 **Q. Was the tax issue discussed in Southern Pioneer's last rate case proceeding,**
18 **Docket No. 09-MKEE-969-RTS (969 Docket)?**

19 A. Yes. Staff Witness Jeffrey D. McClanahan addressed the tax issue in Southern
20 Pioneer's last rate case. Additionally, Staff provided some background of the
21 concerns addressed in the MKEC / Aquila Acquisition Docket No. 06-MKEE-

⁸ See Exhibit LKB-2.

⁹ See Exhibit LKB-6 for Southern Pioneer's Response to Staff Data Request No. 57.

1 524-ACQ (524 Docket). Attached as Exhibit LKB-5 is a copy of the Direct
2 Testimony filed by Mr. McClanahan in the 969 Docket.

3

4 **Q. Has Southern Pioneer met the first filing requirement agreed to in the 524**
5 **Docket, with regards to reporting the status of combining the two entities at**
6 **this time and future prospects?**

7 A. Yes. Southern Pioneer filed its first Compliance Filing on March 29, 2010.

8

9 **Q. What was the result of that filing?**

10 A. Page 3 of the report states:

11 “The Boards concluded that combining Pioneer and Southern at this time
12 provided minimal business value that can otherwise be accomplished through
13 the continuation of two separate business-units; combining before retail
14 customer spin down from MKEC to the distribution company jeopardizes
15 Pioneer’s tax-exempt status; combining exposes Pioneer to unpredictable
16 governance changes or loss of its cooperative status; and combining may harm
17 the existing Pioneer Members.”

18

19 **Q. Has progress been made in combining Southern Pioneer and Pioneer?**

20 A. Based on the March 29th report filed with the Commission it does not appear that
21 progress has been made in combining the two companies. As a result, Staff
22 continues to believe that the alternative ratemaking treatment shall continue in
23 this docket. That is, Staff’s adjustment uses the actual income taxes paid as
24 opposed to the normalized approach.

25

26

27

1 **Q. Did Southern Pioneer pay income taxes in 2009 or 2010?**

2 A. No. Southern Pioneer's tax return Form 1120 indicates that a net operating loss
3 occurred in both years and that Southern Pioneer did not pay any income taxes.
4 Additionally, the Company recognized a federal and Kansas net operating loss
5 carry forward for both years. As a result, Southern Pioneer did not pay any
6 income taxes and most likely will not pay taxes in the near future. Therefore,
7 ratepayers should not be required to pay for an expense that has not occurred.

8

9 **Q. If the Company did not pay any taxes than why does an income tax expense**
10 **exist on the income statement?**

11 A. Southern Pioneer's response to Staff Data Request No. 160A provides
12 reconciliation between book to tax and the associated actual tax paid. In
13 December of 2009 Southern Pioneer recognized a deferred tax asset. Due to the
14 bonus depreciation rules¹⁰, Southern Pioneer was allowed to reflect a more
15 favorable depreciation balance in 2010 than in prior years, resulting in a
16 temporary timing difference between book and tax accounting.¹¹ This rule caused
17 Southern Pioneer to recognize a total change in deferred income taxes of
18 \$1,054,289, resulting in a net deferred liability of [REDACTED].¹²

19

¹⁰ The Job Creation Act of 2010 extended the bonus depreciation allowance for two additional years (2011 and 2012), to provide a significant tax incentive for businesses to make capital investments. It allows taxpayers to deduct at least fifty percent of the cost of qualifying property in addition to the regular depreciation allowance that is normally available.

¹¹ While there are many different types of timing differences that occurred on Southern Pioneer's books, depreciation was the main reason this large timing difference occurred.

¹² See Exhibit LKB-6 for a copy of Southern Pioneer's response to Staff Data Request No. 57.

1 **Q. What level of income taxes did Southern Pioneer recognize in the revenue**
2 **requirement?**

3 A. Exhibit MJW-2 indicates that \$1,054,289 of deferred income tax expense was
4 included in the cost of service. Based on the proposed 2.0 revenue requirement
5 Southern Pioneer included an additional \$1,858,305 in income tax expense related
6 to the pro form revenue increase for a total income tax expense of \$2,912,594.

7

8 **Q. Has Southern Pioneer reflected a double dip in the revenue requirement as it**
9 **pertains to the calculation of income taxes?**

10 A. Yes. As shown on Exhibit MJW-2, Southern Pioneer has recorded \$1,054,289 as
11 an operating expense. Southern Pioneer then adds in an additional income tax
12 expense of \$1,858,305 in the calculation of the revenue requirement on Exhibit
13 RJM-3. This result is a double dip, as only the incremental portion of income
14 taxes totaling \$804,016 related to the pro forma revenue increase should have
15 been included in Southern Pioneer's revenue requirement.

16

17 **Q. Please continue by discussing Staff's Adjustment No. 6 to the income**
18 **statement.**

19 A. Staff Adjustment No. 6 (IS-6) increases Southern Pioneer's non-operating
20 margins by \$785,459, to reverse the impact of Southern Pioneer's adjustment to
21 reclassify the amortization of the acquisition premium as a non-operating
22 expense.¹³ This is necessary to completely remove the amortization of the
23 acquisition premium from Southern Pioneer's revenue requirement. In other

¹³ See Exhibit LKB-3.

1 words, Staff is recording the amortization “below-the-line”, as stipulated in
2 Paragraph 21 of the Stipulation and Agreement approved in Docket No. 06-
3 MKEE-524-ACQ (524 S&A), which states:

4 21. The Acquisition Premium (“AP”) relating to this transaction shall be
5 amortized over a thirty-year period beginning with the Effective Date, and
6 shall be included below-the-line in subsequent MKEC, Distribution
7 Cooperative(s) and Southern Pioneer rate proceedings. The AP shall be
8 considered in the calculation of TIER for purposes of determining if a
9 refund is due as provided for herein. Notwithstanding, the signatories
10 agree that in subsequent retail rate case(s) filed after the Effective Date by
11 MKEC, Distribution Cooperative(s) or Southern Pioneer, the
12 determination of the total revenue requirement shall be sufficient to take
13 into consideration generally acceptable financial covenants, debt costs and
14 acceptable levels of equity and cash reserves of MKEC, the Distribution
15 Cooperative(s) or Southern Pioneer, as the case may be. Hereafter,
16 estimated savings associated with this transaction shall not be subject to
17 review in subsequent rate case filed by MKEC, the Distribution
18 Cooperative(s) or Southern Pioneer.
19

20 **Q. How does the treatment of the amortization of the acquisition premium**
21 **differ from Southern Pioneer’s treatment?**

22 A. Exhibit RJM-2 shows that Southern Pioneer reclassifies the expense as a non-
23 operating expense, but fails to make a corresponding adjustment to revenues,
24 therefore Mr. Macke has improperly classified the expense as “below-the-line” as
25 directed in the S&A.
26

27 **Q. Does Staff Agree with Southern Pioneer’s adjustment to include the**
28 **acquisition premium as a non-operating expense?**

29 A. No. Staff interprets Paragraph 21 of the S&A to mean that the amortization of the
30 acquisition premium should not be explicitly included in Southern Pioneer’s rates.

1 “Below-the-line” is a common expression in regulation and it nearly always
2 carries the connotation that those expenses will not be charged to a utility’s
3 ratepayers. Mr. Macke’s treatment of the acquisition premium simply moves
4 \$785,459 from “amortization expense” to “non-operating expense”, with no
5 corresponding decrease in the requested revenue requirement. Staff’s adjustment
6 is consistent with the intent of the S&A to remove the amortization of the
7 acquisition premium from Southern Pioneer’s revenue requirement.

8

9 **Q. How does Staff’s recommendation to remove the amortization of the**
10 **acquisition premium comport with the second sentence of Paragraph 21 of**
11 **the S&A that requires that “The AP shall be considered for purposes of**
12 **calculating TIER and other financial ratios...”?**

13 A. Staff’s adjustment accomplishes that directive. Staff has not made any adjustment
14 to remove any of the interest expense or principle payments associated with the
15 financing of the acquisition premium from Southern Pioneer’s cost of service.
16 Therefore, the full impact of the acquisition premium is included in Staff’s
17 calculation of TIER and DSC. If the amortization of the acquisition premium
18 were to be left in the case as a reduction to non-operating income, Southern
19 Pioneer’s DSC would be approximately 15 basis points (1.85 vs. 2.0) lower, as
20 calculated by Staff’s revenue requirement schedules.

21

22 **Q. What is the revenue requirement impact of Staff’s adjustment to remove the**
23 **acquisition premium?**

1 A. Staff's revenue requirement is approximately \$787,992 less than otherwise would
2 be the case if the amortization of the acquisition premium was left in as a
3 reduction to non-operating income. However, it is important to note that because
4 Staff's revenue requirement recommendation is based on the DSC ratio, Staff's
5 revenue requirement would be the same if the amortization of the acquisition
6 premium were to be included as amortization expense, instead of removed from
7 the case altogether. The revenue requirement impact occurs because Southern
8 Pioneer reclassified the amortization expense to a non-operating expense.

9 Because the DSC calculation adds back amortization and depreciation
10 expense to net margins to determine the overall cash flow available for debt
11 service, the overall level of depreciation and amortization expense in the income
12 statement is irrelevant. However, non-operating expense doesn't get this same
13 treatment. Because it reduces net margin, it directly lowers the DSC calculation.

14 In other words, when using the DSC ratio to determine the revenue
15 requirement, Southern Pioneer's treatment of the acquisition premium
16 (reclassifying it as a non-operating expense) causes an increase to Southern
17 Pioneer's revenue requirement that would not exist if the amortization expense
18 was not classified and left as amortization expense, or if it was removed from the
19 revenue requirement calculation altogether.

20

21

22

1 **Q. Please continue by discussing Staff Adjustment No. 7 to the income**
2 **statement.**

3 A. Staff Adjustment No. 7 (IS-7) decreases Southern Pioneer's pro forma test year
4 customer account expense by \$2,168. Staff's net bad debt write-off percentage is
5 calculated by dividing net write-offs (bad debt write-offs less bad debt recoveries)
6 by sales of electric revenue. Staff used a three year average of net-write-off's to
7 calculate the factor used in the bad debt expense adjustment. As shown on
8 Exhibit LKB-4, it appears Southern Pioneer's net bad debt write-off percentage
9 has been decreasing since 2009. While the test year write-off percentage may
10 seem reasonable, it is clear that the level of debt to be written off is constantly
11 changing; therefore, the write-off percentage is likely to fluctuate in the future.
12 As a result, a three-year average will be more representative of the ongoing,
13 normal level of bad debt expense Southern Pioneer can expect to incur in the
14 future.

15

16 **SUMMARY OF STAFF EXHIBITS**

17

18 **Q. Are you sponsoring any exhibits?**

19 A. Yes. The following provides an outline of the exhibits I sponsor:

20	<u>Exhibit No.</u>	<u>Description</u>
21	LKB-1 to 1 (e)	Local Access Charge Revenues
22	LKB-2	Income Taxes
23	LKB-3	Acquisition Premium

Direct Testimony of Laura K. Bowman
Docket No. 12-MKEE-380-RTS

- | | | |
|---|-------|------------------------------|
| 1 | LKB-4 | Bad Debt |
| 2 | LKB-5 | Testimony of Jeff McClanahan |
| 3 | LKB-6 | Data Request Responses |
| 4 | LKB-7 | CFC Key Trend Ratio Analysis |

5

6 **Q. Does this conclude your testimony?**

7 A. Yes, thank you.

Exhibit LKB-1 to 1(e)

Income Statement Adjustment No. 4

Local Access Charge

Southern Pioneer Electric Company
MKEC Area Local Access Charge
Input Data

Test Year Jan 1, 2010 to Dec 31, 2010
Adjusted for Known and Measurable Changes through Year End 2011

A. Net Plant in Service

Description	Source	As of December 31, 2011		Depr. Rate	Notes
		Plant in Service	Accum. Res. for Depr.		
1. Facilities Used to Provide LA Service					
Transmission Facilities					
350 Land and Land Rights	Staff Exhibit ANF-1	100,239	-	-	
352 Structures and Improvements	Staff Exhibit ANF-1	-	-	0.02060	
353 Station Equipment	Staff Exhibit ANF-1	5,464,065	-	0.01820	
355 Poles and Fixtures	Staff Exhibit ANF-1	5,790,083	-	0.03300	
356 O.H. Conductors and Devices	Staff Exhibit ANF-1	5,801,882	-	0.01880	
358 U.G. Conductors and Devices		-	-	-	
Subtotal		17,156,269	6,497,825	0.02329	
Distribution Facilities					
360 Land and Land Rights		-	-	-	
361 Structures and Improvements		-	-	-	
362 Station Equipment		-	-	-	
Subtotal		-	-	-	
Total		17,156,269	6,497,825	0.02329	
2. All Facilities					
Intangible Plant		-	-	-	
Transmission Plant	Response to Staff DR 154	17,156,269	6,497,825		
Distribution Plant	Response to Staff DR 154	40,097,570	14,665,129		
General Plant	Response to Staff DR 154	5,683,045	1,671,474		
Total		62,936,884	22,834,428		

B. Operating Expenses

		Pro Forma Test Year	
Transmission O&M	Staff Schedule B-1, Line 6	708,114	
Distribution O&M	Staff Schedule B-1, Lines 7-8	3,589,676	
Administrative and General	Staff Schedule B-1, Line 12	1,202,533	
Property Tax	Staff Schedule B-1, Line 14	-	
L.T. Interest	Staff Schedule B-1, Line 19	4,547,758	
RUS Buyout	Staff Schedule B-1, Line 21	322,880	

C. Payroll

		Staff Adjusted Payroll
Transmission	Staff Exhibit KAL - 2	36,832
Distribution	Staff Exhibit KAL - 2	1,247,545
Customer Accounting	Staff Exhibit KAL - 2	501,306
Customer Service and Information	Staff Exhibit KAL - 2	15,035
Sales	Staff Exhibit KAL - 2	-
Administration and General	Staff Exhibit KAL - 2	439,874
Total		2,240,592

D. Miscellaneous

		As of 12/31/11	Depr. Rate
Target DSC			2.0
General Plant			
389 Land and Land Rights		140,161	-
390 Structures and Improvements		1,677,028	0.03160
391 Office Furniture and Equipment		413,512	0.07680
392 Transportation Equipment		2,662,575	0.11560
393 Stores Equipment		215,299	0.04750
394 Tools, Shop and Garage Equip		22,193	0.04650
395 Laboratory Equipment		178,239	0.04980
396 Power Operated Equipment		-	0.06970
Communication Equipment		332,611	0.02330
Miscellaneous Equipment		41,426	0.07420
Total	\$	5,683,044	

Southern Pioneer Electric Company
MKEC Area Local Access Charge
Revenue Requirements

Test Year Jan 1, 2010 to Dec 31, 2010
Adjusted for Known and Measurable Changes through Year End 2011

Line	Description	Source	Total MKEC Area	Allocation Factor		Allocated to LAC	Percent of Total
				Name	Factor		
1	Operating Expenses						
2	Transmission O&M		\$ 708,114		1.000000	\$ 708,114	27.81%
3	Distribution O&M		3,589,676	DOM	0.000000	-	0.00%
4	Administration & General		1,202,533	LAB	0.020454	24,597	0.97%
5	Depreciation						
6	Transmission	Exhibit LKB-1 (c), Line 9	399,594		1.000000	399,594	15.70%
7	Distribution (LAC Only)		-		1.000000	-	0.00%
8	General Plant	Exhibit LKB-1 (c), Line 29	423,504	LAB	0.020454	8,662	0.34%
9	Property Taxes		-	NP	0.267826	-	0.00%
10	RUS Buyout		322,880	NP	0.239904	77,460	3.04%
11	Subtotal Operating Expense					\$ 1,218,427	
12	L.T. Interest Expense	Staff Schedule B-1, Line 19	4,547,758	NP	0.267826	\$ 1,218,010	47.84%
13	DSC Requirement						
14	Margin Requirement	Staff Schedule B-1, Line 28	4,956,351	NP	0.267826	\$ 1,327,442	
15	Margin					\$ 109,432	4.30%
16	Income Tax Requirement @ 63.620%					\$ -	0.00%
17	Total Revenue Requirements					\$ 2,545,869	100.00%
18	Billing Demand	Staff Exhibit LKB-1 (e)				1,058,117 kW	
19	Average Cost					\$ 2.41 /kW/mo	

Southern Pioneer Electric Company
MKEC Area Local Access Charge
Allocation Factors

Test Year Jan 1, 2010 to Dec 31, 2010
Adjusted for Known and Measurable Changes through Year End 2011

Line No.	Description	Source	
1	Distribution O&M Allocation Factor		
2	Distribution Plant used in LAC		\$ -
3	Total Distribution Plant	N/A	\$ 40,097,570
4			
5	Allocation Factor		DOM -
6			
7	Labor Allocation Factor		
8	Transmission Wages (100% LAC)	Exhibit KAL - 2	\$ 36,832
9	Distribution Wages		
10	Total Distribution Wages	Exhibit KAL - 2	\$ 1,247,545
11	Allocation Factor		DOM -
12	Dist Wages Allocated to LAC		\$ -
13	Total LAC Wages		\$ 36,832
14			
15	Total Wages	Exhibit KAL - 2	\$ 2,240,592
16	Less: Administration & General Wages	Exhibit KAL - 2	439,874
17	Wages Other than A&G		\$ 1,800,718
18			
19	Labor Allocator		LAB 0.020454
20			
21	Net Plant Allocation Factor		
22	Plant-in-Service		
23	Transmission	Staff Exhibit ANF-1	\$ 17,156,269
24	Distribution		-
25	Subtotal		\$ 17,156,269
26	Allocated General Plant		
27	Total General Plant	Staff Exhibit ANF-1	\$ 5,683,045
28	Allocation Factor		LAB 0.020454
29	Allocated General Plant		\$ 116,241
30	Total LAC Plant-in-Service		\$ 17,272,510
31			
32	Accumulated Reserves for Depreciation		
33	Transmission	Response to Staff DR 154	\$ 6,497,825
34	Distribution		-
35	Subtotal		\$ 6,497,825
36	Allocated General Plant		
37	Total General Plant	Response to Staff DR 154	\$ 1,671,474
38	Allocation Factor		LAB 0.020454
39	Allocated General Plant		\$ 34,188
40	Total LAC Accum. Res. For Depr.		\$ 6,532,013
41	Net Plant Used in LAC		\$ 10,740,497
42			
43	Total Plant in Service		\$ 62,936,884
44	Total Accum. Reserves for Depr.		22,834,428
45	Total Net Plant		\$ 40,102,456
46			
47	Net Plant Allocator		NP 0.267826
48			

Southern Pioneer Electric Company
MKEC Area Local Access Charge
Depreciation Expense

Test Year Jan 1, 2010 to Dec 31, 2010
Adjusted for Known and Measurable Changes through Year End 2011

<u>Line</u>	<u>Description</u>	<u>Source</u>	<u>Plant in Service as of 12/31/11</u>	<u>Depr. Rate</u>	<u>Depr. Expense</u>
1	Facilities Used in Providing LAC Service				
2	Transmission Facilities				
3	350 Land and Land Rights	Staff Exhibit ANF-1	\$ 100,239	-	\$ -
4	352 Structures and Improvements	Staff Exhibit ANF-1	-	0.02060	-
5	353 Station Equipment	Staff Exhibit ANF-1	5,464,065	0.01820	99,446
6	355 Poles and Fixtures	Staff Exhibit ANF-1	5,790,083	0.03300	191,073
7	356 O.H. Conductors and Devices	Staff Exhibit ANF-1	5,801,882	0.01880	109,075
8	358 U.G. Conductors and Devices		-	-	-
9	Subtotal		\$ 17,156,269		\$ 399,594
10	Distribution Facilities				
11	360 Land and Land Rights		\$ -	-	-
12	361 Structures and Improvements		-	-	-
13	362 Station Equipment		-	-	-
14	Subtotal		\$ -		\$ -
15	Total		\$ 17,156,269		\$ 399,594
16					
17			<u>As of 12/31/11</u>		
18	General Plant				
19	389 Land and Land Rights	Response to Staff DR 154	\$ 140,161	-	\$ -
20	390 Structures and Improvements	Response to Staff DR 154	1,677,028	0.031600	52,994
21	391 Office Furniture and Equipment	Response to Staff DR 154	413,512	0.076800	31,758
22	392 Transportation Equipment	Response to Staff DR 154	2,662,575	0.115600	307,794
23	393 Stores Equipment	Response to Staff DR 154	215,299	0.047500	10,227
24	394 Tools, Shop and Garage Equip	Response to Staff DR 154	22,193	0.046500	1,032
25	395 Laboratory Equipment	Response to Staff DR 154	178,239	0.049800	8,876
26	396 Power Operated Equipment	Response to Staff DR 154	-	0.069700	-
27	Communication Equipment	Response to Staff DR 154	332,611	0.023300	7,750
28	Miscellaneous Equipment	Response to Staff DR 154	41,426	0.074200	3,074
29	Total		\$ 5,683,044	0.074521	\$ 423,504
30					
31	Plant in Service as of 12/31/11		\$ 5,683,045	0.074521	\$ 423,504
32					

Southern Pioneer Electric Company
 MKEC Area Local Access Charge
 Credit for Third Party Revenue

Test Year Jan 1, 2010 to Dec 31, 2010
 Adjusted for Known and Measurable Changes through Year End 2011

<u>Line</u>	<u>Description</u>	<u>Source</u>	<u>Alloc. Factor</u>	<u>Amount</u>	<u>Notes</u>
1	Total Revenue Credit				
2	Third Party Billing Demand			396,089	kW
3	LAC Rate			\$ 2.41	/kW/mo
4	LAC Third Party Revenue			\$ 953,006	
5					
6	Allocation of Revenue Credit to Categories				
7	Transmission O&M		27.81%	\$ 265,071	
8	Distribution O&M		0.00%	-	
9	Administration and General		0.97%	9,207	
10	Depreciation		16.04%	152,824	
11	Property Taxes		0.00%	-	
12	Other Deductions		3.04%	28,996	
13	L.T. Interest		47.84%	455,943	
14	Margin Requirements		4.30%	40,964	
			0.00%	-	
15	Total		100.00%	\$ 953,006	
16	Southern Pioneer's LAC Third Party Revenue (Present Rates Exhibit RJM-2, Page 6)			\$779,543	
17	Staff's LAC Third Party Revenue			953,006	
18	Staff's Adjusted LAC Third Party Revenue			<u>173,463</u>	

Southern Pioneer Electric Company
Summary of Proposed Local Access Billing Demands (kW) -- 2010

Line	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	Total Local Access System	82,317	77,973	70,204	69,464	85,465	114,174	118,581	115,342	111,227	79,676	79,237	74,137	1,077,798
2	CP Date	07	08	24	07	29	22	14	02	15	07	29	01	
3	CP Time (hour Ending)	2000	2000	2000	1100	1700	1600	1600	1600	1600	1600	1900	2100	
4														
5	Wholesale Customers @ Del. Pt.													
6	Ashland (KMEA)--Metered	1,980	1,917	1,647	1,729	2,155	3,357	3,638	3,740	3,267	2,095	1,693	1,772	28,989
7	Ashland (KMEA)--Generation	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Subtotal--Ashland	1,980	1,917	1,647	1,729	2,155	3,357	3,638	3,740	3,267	2,095	1,693	1,772	28,989
9	Kingman (KPP)	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	72,000
10	Kingman (KPP) Generation	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Subtotal--Kingman	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	72,000
12	Greensburg	2,729	2,374	1,698	1,651	1,704	2,373	2,518	2,432	2,108	1,593	1,847	1,709	24,736
13	Greensburg Wind Farm (1)	10,408	10,787	10,718	11,845	8,498	9,325	7,776	4,880	9,253	3,608	11,741	10,583	109,421
14	Isabel (AR)	314	293	252	281	243	296	247	269	321	305	273	272	3,367
15	KEPCO	14,047	13,006	10,703	10,414	13,637	14,391	13,600	15,409	16,789	14,040	11,122	10,416	157,576
16	Subtotal--Wholesale	35,478	34,376	31,017	31,920	32,237	35,743	33,779	32,730	37,738	27,642	32,675	30,753	396,089
17	Losses @ 1.86% of 34.5 kV Output	660	639	577	594	600	665	628	609	702	514	608	572	7,367
18	Subtotal with Losses (@ Source)	36,138	35,016	31,594	32,514	32,837	36,408	34,408	33,339	38,440	28,156	33,282	31,325	403,456
19														
20	Southern Pioneer Retail													
21	Retail with Losses (@ Source)	46,179	42,958	38,609	36,950	52,628	77,766	84,173	82,004	72,787	51,520	45,955	42,812	674,341
22	Losses @ 1.83% of 34.5 kV Input	843	784	705	675	961	1,420	1,537	1,497	1,329	941	839	782	12,314
23	Retail @ Delivery Point	45,336	42,173	37,904	36,275	51,667	76,346	82,636	80,506	71,458	50,580	45,116	42,031	662,028

(1) Per the Commission Order in Docket No. 11-GIME-597-GIE, Greensburg Wind Farm is now calculated based on a coincident peak.

Source: Southern Pioneer's Response to Staff Data Request No. 198

Southern Pioneer Electric Company
Income Tax Expense
Income Statement Adjustment No. 5
Test Year Ended December 31, 2010

Docket No. 12-MKEE-380-RTS
Exhibit LKB-2

Line No.	Description	Account Number	Amount
1	Federal and State Income Taxes recorded in the test year		1,054,289
2	Staff's Adjustment Taxes - Other	410.1	<u>(1,054,289)</u>

Source: Southern Pioneer's Application, Exhibit RJM-2, Page 1, Line 17

Source: Southern Pioneer's response to Staff Data Request No. 2, 57, 160A

Source: Southern Pioneer's response to KEPCO Data Request No. 36, 2-4, 2-5, 2-6, 5-13

Southern Pioneer Electric Company
Acquisition Premium
Income Statement Adjustment No. 6
Test Year Ended December 31, 2010

Docket No. 12-MKEE-380-RTS
Exhibit LKB-3

Line No.	Description	FERC Account	Amount
1	Amortization of Acquisition Premium		<u>785,459</u>
2	Staff's Adjustment to Non-Operating Margins - Other	998	<u><u>785,459</u></u>

Source: Southern Pioneer's Application - Exhibit RJM-2, Page 1 of 20, Line 25

Southern Pioneer Electric Company
 Bad Debt Expense
 Income Statement Adjustmtnent No. 7
 Test Year Ended December 31, 2010

Docket No. 12-MKEE-380-RTS
 Exhibit LKB-4

Line No.	Description	FERC Account	Amount
1	Staff Pro Forma Electric Revenues		60,594,681
2	Southern Pioneer's Bad Debt Expense Ratio		<u>0.169580%</u>
3	Staff Adjusted Bad Debt Expense		102,756
4	Southern Pioneer's Test Year Bad Debt		<u>104,925</u>
5	Staff Adjustment to Bad Debt Expense		<u><u>(2,168)</u></u>

Calculation of Net Bad Debt Write Off Percentage

Line No.	Year	Sales of Electric Revenues	Bad Debt Write Off	Bad Debt Recoveries	Net Bad Debt Write Off
6	2009	47,744,967	206,366	50,787	0.32585%
7	2010	57,844,085	115,525	52,883	0.10829%
8	2011	60,048,666	97,112	52,321	0.07459%
9				3-Year Average	0.169580%

Source: Southern Pioneer's Response to Staff Data Request No. 59, 111

Exhibit LKB-5

Direct Testimony of Staff Witness

Jeffrey D. McClanahan in

Docket No. 09-MKEE-969-RTS

IN THE MATTER OF THE APPLICATION OF MID-)
KANSAS ELECTRIC COMPANY, LLC FOR)
APPROVAL TO MAKE CERTAIN CHANGES IN ITS)
CHARGES FOR ELECTRIC SERVICE)

DOCKET No. 09-MKEE-969-RTS

STATE CORPORATION COMMISSION

OCT 19 2009



DIRECT TESTIMONY

PREPARED BY

JEFFREY D. McCLANAHAN

UTILITIES DIVISION

KANSAS CORPORATION COMMISSION STAFF

1 **Q. Please state your name and business address.**

2 A. Jeffrey D. McClanahan, 1500 SW Arrowhead Road, Topeka, Kansas.

3

4 **Q. Who is your employer and what is your title?**

5 A. I am employed by the Kansas Corporation Commission (“Commission” or
6 “KCC”) as the Chief of Accounting and Financial Analysis.

7

8 **Q. What is your educational background and professional experience?**

9 A. I hold a Bachelor of Arts degree in Accounting from West Texas State
10 University. I was employed for approximately eight years by a Savings and Loan
11 institution in professional positions in auditing and accounting. I joined the KCC
12 in December 1997 as a Utility Auditor II. I was promoted to Senior Auditor in
13 May 1998 and was subsequently promoted to my present position in February
14 2002. I am a Certified Internal Auditor.

15

16 **Q. Have you previously testified before the Commission?**

17 A. Yes, I have filed testimony in numerous dockets before the Commission.

18

19 **Q. What is the purpose of your testimony?**

20 A. I am addressing Southern Pioneer Electric Company’s (Southern Pioneer)
21 income tax expense, Wheatland Electric Cooperative, Inc.’s (Wheatland) request
22 to implement an Energy Cost Adjustment (ECA) rider and Mid-Kansas Electric
23 Company, LLC’s (MKEC) Clarification Filing regarding its ECA. Because I am

1 addressing MKEC and two separate divisions within Mid-Kansas, I will separate
2 this testimony into three sections. One section will address MKEC and the other
3 sections will address Southern Pioneer and Wheatland respectively.

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1 **Q. Please discuss Staff's concerns from the 524 Docket.**

2 A. David N. Dittmore addressed the Southern Pioneer tax issue in his direct
3 testimony in the 524 Docket. Specifically, Dittmore stated the following:

4 The election by Pioneer to form a taxable corporation is an
5 issue that Staff has struggled with. Staff believes that one of the
6 primary benefits of this transaction is the acquiring entities are
7 member owned cooperatives. These cooperative members share
8 in the margins of the cooperative and are tax-exempt entities,
9 providing substantial benefits to ratepayers over investor owned
10 utilities. The election by Pioneer to establish a taxable entity
11 denies these benefits to its acquired WPK customers. [Direct
12 Testimony of David N. Dittmore, p. 43, ll. 4-10].
13

14 Dittmore further provided a discussion of the reasons for Pioneer's decision to
15 establish Southern Pioneer as a taxable C-Corporation and Staff's reaction and
16 position. The relevant section of Dittmore's testimony is attached as Staff Exhibit
17 JDM - 1, portions of which are confidential.

18

19 **Q. Did Staff make any recommendations regarding Southern Pioneer's C-**
20 **Corporation election in the 524 Docket?**

21 A. Yes. Staff made specific recommendations regarding Southern Pioneer's
22 taxable status. The goal of the recommendations was to ensure that Pioneer
23 continued to seek solutions that would enable Pioneer to offer full cooperative
24 membership to the acquired WPK customers and to prevent possible subsidization
25 of Pioneer's customers by Southern Pioneer's customers. These
26 recommendations are included in Staff Exhibit JDM-1 at pages 46 and 47. I will
27 not summarize the recommendations here because the Stipulation and Agreement

1 (S&A) in the 524 Docket identifies the conditions that the parties negotiated and
2 the Commission authorized.

3

4 **Q. What are the conditions related to Southern Pioneer's tax issue in the 524**
5 **S&A?**

6 A. There are numerous conditions in the 524 Docket that apply to all of the
7 member-owners of MKEC and to MKEC specifically, but there are also
8 conditions that apply specifically to Southern Pioneer. The pertinent condition
9 that is related to Staff's concerns about Southern Pioneer's tax status states:

10 Pioneer and Southern Pioneer will jointly file a report every three
11 years, in the event combination has not occurred, to inform the
12 Commission on the status of the prospective combination [524 Docket,
13 Stipulation and Agreement at paragraph 28].
14

15 The intent of the condition noted above was to provide Staff and the
16 Commission an update on the progress and current issues, if any, prohibiting the
17 combination of Southern Pioneer and Pioneer so that Southern Pioneer's members
18 can receive the full benefit of belonging to a cooperative. The first progress
19 report is not due until 2010.

20

21 **Q. Does the 524 Docket's S&A indicate how Southern Pioneer's income taxes**
22 **are to be addressed be in a rate case?**

23 A. No, the 524 Docket's S&A is silent regarding the treatment of Southern
24 Pioneer's income taxes in rate cases, mainly because Staff's testimony in support
25 of the stipulation included notation of a right – to recommend disallowance of an

1 expense or alternative treatment of the expense – that Staff always has.
2 Therefore, there was no need to explicitly state the right in the S&A. Specifically,
3 Staff's Testimony in Support of Settlement sponsored by David N. Dittimore,
4 indicates the following:

5 Other reporting requirements are in place that will permit Staff to
6 monitor Southern Pioneer's progress in achieving full co-op status for
7 the acquired customers. *Based on, in part, the progress reports, if*
8 *Staff determines that sufficient progress is not being made to*
9 *ultimately provide the benefits of this transaction to Southern Pioneer*
10 *customers equivalent to those enjoyed by other former WPK*
11 *customers, Staff reserves the right to offer alternative ratemaking*
12 *proposals to the Commission in subsequent dockets, including*
13 *disallowance of any costs Staff deems imprudent as a result of its*
14 *[Southern Pioneer's] corporate status. It is Staff's position that*
15 *absent full co-op membership for these customers at some point in the*
16 *future, this transaction does not meet the positive benefits test*
17 *consistent with the standards outlined in the Commission's order in*
18 *Docket Nos. 172,745-U and 174,155-U (KPL/KGE Merger). [524*
19 *Docket, David N. Dittimore Testimony in Support of Settlement at*
20 *page 9, lines 7-18]. [Emphasis added].*

21
22 Therefore, even though the 524 Docket's S&A is silent regarding how
23 Southern Pioneer's income taxes might be treated, Staff's testimony in support of
24 the S&A clearly indicates that we may recommend alternative ratemaking
25 treatment or even disallowance in rate cases based on the progress being made to
26 combine Southern Pioneer and Pioneer.

27

28 **Q. Based on the S&A from the 524 Docket, what is Staff's rationale for**
29 **recommending that Southern Pioneer's income tax expense be set at \$0?**

30 **A.** Staff is offering an alternative ratemaking treatment. That is, the use of
31 actual income taxes paid as opposed to the normalization approach. To be clear,

1 Staff is *not* recommending that income taxes be disallowed. Staff believes that it
2 is premature to recommend disallowance because the first report detailing Pioneer
3 and Southern Pioneer's progress in combining has not been filed. Rather,
4 Southern Pioneer did not pay any income taxes in 2008, so Staff is recommending
5 that the actual taxes paid approach be used in this case.
6

7 **Q. Please explain the difference between normalization and the flow-through/
8 actual income taxes paid approach.**

9 A. Investor-owned utilities are taxable entities and as such income taxes are
10 included in a revenue requirement determination. The cumulative affect of
11 income taxes for an investor-owned utility is determined using a normalization
12 approach. The normalization approach to income taxes refers to the use of
13 deferred income taxes in the ratemaking process. Deferred income taxes arise
14 from book/tax timing differences. Book/tax timing differences are generated by a
15 number of items, but the most common item is the difference between tax
16 deductions for depreciation and book depreciation expense. Tax depreciation is
17 generally computed based on accelerated rates over relatively short periods of
18 time. Book depreciation is calculated, for ratemaking purposes in particular,
19 using the straight-line method over the estimated lives of the respective assets. It
20 is the difference between book and tax depreciation expense – resulting from the
21 use of different methods and lives – that creates a timing difference. A tax rate is
22 applied to the timing difference to determine the amount of deferred income tax
23 generated.

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The normalization of income taxes for investor-owned utilities has been described as follows:

Income taxes affect revenue requirements in several ways. First, they are a significant component of the cost of service. Assuming a 40% combined Federal-state tax rate, every \$1.00 of income tax expense represents \$1.67 of revenue requirements. The second way in which income taxes affect revenue requirements is the ability of regulators to use the balance of Accumulated Deferred Income Taxes ("ADIT") as a rate base deduction, or in the alternative, as a zero-cost component of capital structure for rate of return purposes. Using the same 40% combined Federal-state income tax rate and a 10% rate of return, \$1.00 of ADIT deducted from rate base, reduces revenue requirements by approximately \$.17, all things else remaining unchanged.

Current Income Taxes represent the computed tax liability, based on proforma test year jurisdictional operating revenues and expenses, as though actual returns were being prepared for Federal and State income taxes. Deferred Income Taxes represent the computed income tax effect of book-tax "timing differences". Timing differences are revenues and expenses recognized in different periods for book and tax purposes.

When Deferred Income Taxes are recorded as a part of income tax expense, a corresponding entry is made to a balance sheet account labeled "Accumulated Deferred Income Taxes". Deferred Income Taxes included in cost of service will be recovered in rates prior to the time at which they must be remitted to the respective taxing authority. In the interim, they represent a source of funds available for additional capital investment or other corporate purposes. As stated, ADIT may either be deducted from rate base or treated as a zero-cost element of capital structure.

Over the years, Deferred Income Taxes have been the most complex and controversial element of income tax expense in the ratemaking process. As stated, Deferred Income Taxes are computed as the tax effect of book-tax timing differences, and tend to offset the effect of timing differences reflected in the calculation of Current Income Taxes, thereby providing a levelizing effect on total income tax expense. In ratemaking, the process of including Deferred Income Taxes in cost of service is labeled "normalization".

1 [Course material from Public Utility Income Taxation and
2 Ratemaking, Carl W. Dabelstein, CPA, I-5].³
3

4 While the ratemaking implications of the normalization approach to
5 income taxes are complicated, the flow-through or actual taxes paid approach is
6 relatively straight forward. Under the actual taxes paid approach, the differences
7 between book and tax income (deferred taxes) are ignored, and any tax benefits
8 are passed on to ratepayers in current income tax reductions in rates. Simply said,
9 only the actual income taxes paid to Federal and State income tax authorities are
10 reflected in the revenue requirement determination.
11

12 **Q. What is Staff's rationale for recommending that Southern Pioneer use the**
13 **actual taxes paid approach?**

14 **A.** As defined above, investor-owned utilities use the normalization approach
15 to income taxes. In doing so, they include all aspects of the normalization
16 approach. That is, the income tax expense is calculated by the use of a tax factor
17 to "gross-up" required revenues such that net income after taxes meets the
18 revenues required and the benefits of deferred taxes are included as an offset to
19 rate base. In the current case, Southern Pioneer has "grossed-up" its revenue
20 requirement to include income tax expense. But Southern Pioneer's revenue
21 requirement is based on the cooperative model of setting rates based on a Times
22 Interest Earned ratio (TIER) and Debt Service Coverage ratio (DSC). Therefore

³ The examples using tax rates, such as the \$1.67 reference were calculated using slightly different tax rates than those that are in effect today.

1 rate base and rate of return are not used to determine Southern Pioneer's revenue
2 requirement. Because rate base and rate of return are not used, there is no way for
3 Southern Pioneer to include the offsetting benefits of deferred taxes in
4 determining its revenue requirement.

5 Based on the fact that Southern Pioneer cannot pass on the benefits of
6 deferred taxes, Staff believes that a reasonable approach is to use the actual taxes
7 paid approach. Clearly, it does not make sense for Southern Pioneer to include
8 \$2,084,469 in Federal and State income tax expense when its actual taxes for
9 2008 were \$0 and it cannot fully implement the normalization approach to income
10 taxes.

11

12 **Q. Does Staff believe that Southern Pioneer should use the rate base/ rate of**
13 **return approach used by investor-owned utilities?**

14 **A.** No. Staff is appreciative of the fact that Southern Pioneer has abided by
15 its "gentlemen's" agreement to set rates as if Southern Pioneer is a non-profit
16 cooperative.⁴ The current tax issue is a problem derived from the fact that
17 Southern Pioneer is attempting to achieve a hybrid approach of a taxable entity
18 operating as if it is a non-profit. Staff asserts that Staff's approach is reasonable
19 and should be used to determine the income tax expense to be allowed Southern
20 Pioneer in this case. The proper method to determine income tax expense or

⁴ Staff recommended a condition in its direct testimony that Southern Pioneer explicitly agree to operate as a non-profit. See Staff Exhibit JDM-1 at page 42, Item 4. It is Staff's recollection that Southern Pioneer had reservations regarding explicitly stating it would operate as a non-profit in a Stipulation and Agreement, but that it informally agreed to do so.

1 whether income taxes should be disallowed can be addressed again in any future
2 rate case after Pioneer and Southern Pioneer report on the progress and issues
3 related to combining Southern Pioneer and Pioneer.

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Wheatland

Q. Please discuss Wheatland’s request to establish an ECA.

A. MKEC’s Application in this case notes at paragraph 10 that “Mid-Kansas and the Mid-Kansas Members (with the exception of Wheatland Electric Cooperative, Inc.) now desire to file for changes in rates that reflect the current cost of service for Mid-Kansas and each of the Mid-Kansas Members as follows:”. As paragraph 10 indicates, Wheatland has not filed for a divisional rate change in the current case. However, the list of changes in rates referred to in the cite noted above includes a request for “Establishment of an ECA for Wheatland Electric for use with sales made to Mid-Kansas retail customers served by Wheatland Electric”.

Staff assumes the request for the establishment of an ECA for Wheatland to be an error. If MKEC did intend to request an ECA for Wheatland, Staff is opposed to the request. Staff’s rationale is based on the fact that an ECA cannot be established outside the context of a full rate case because the fuel and purchased power costs must be removed from base rates first in order to establish an ECA. Moreover, MKEC has not provided any specific proposed tariff or analysis in its current filing to support this request.

1 recent discussions with MKEC regarding how to recover the capital costs on a
2 going forward basis. During these discussions, Staff gained further insight into
3 how the capital costs are recorded and the relationship of the capital costs to the
4 JEC PPA. Essentially, Staff now understands that the JEC PPA capital costs are
5 recorded as a component of Account 555 – Purchased Power and that the capital
6 costs are directly related to the JEC PPA. To be clear, while the JEC PPA
7 charges incurred by MKEC are called capital costs, they are capital costs incurred
8 by Westar and passed on directly to MKEC thorough the JEC PPA. Most
9 importantly, MKEC does not have any ownership interest in JEC, therefore the
10 nature of the capital cost charges to MKEC are truly expenses in nature.

11

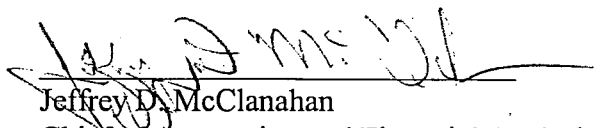
12 **Q. Does this conclude your testimony?**

13 **A. Yes, it does.**

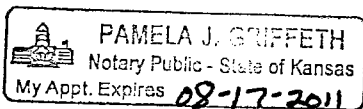
STATE OF KANSAS)
) ss.
COUNTY OF SHAWNEE)

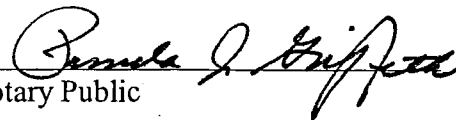
VERIFICATION

Jeffrey D. McClanahan, being duly sworn upon his oath deposes and says that he is the Chief of Accounting and Financial Analysis for the State Corporation Commission of the State of Kansas, that he has read and is familiar with the foregoing *Direct Testimony*, and that the statements contained therein are true and correct to the best of his knowledge, information and belief.


Jeffrey D. McClanahan
Chief of Accounting and Financial Analysis,
Utilities Division
State Corporation Commission of the
State of Kansas

Subscribed and sworn to before me this 19th day of October, 2009.




Notary Public

My Appointment Expires:

August 17, 2011

STAFF EXHIBIT JDM-1

REDACTED VERSION

REDACTED

Direct Testimony of David N. Dittmore
Docket No. 06-MKEE-524-ACQ

1 The terms of the agreement whereby MKEC assumes the unfunded OPEB
2 liability is not just and reasonable. Staff strongly objects to this aspect of the
3 Sales Agreement. Staff recommends, as a condition to approving the transaction,
4 that WPK submit funds to MKEC equal to its balance of Accrued OPEB Liability
5 (Account 253) as of the date of closing. MKEC should then allocate these funds
6 among distribution cooperatives based upon the underlying OPEB liability
7 assumed by each distribution cooperative, at the date that distribution assets are
8 spun-down.

9
10 The fourth condition is required to ensure MKEC and its distribution cooperatives
11 are provided with a complete set of accounting records upon closing of the
12 transaction. This condition is necessary to make certain that future rate filings of
13 MKEC members may be fully supported and in compliance with Kansas Statutes
14 and to ensure appropriate records are available in the discovery phase of
15 subsequent rate investigations. Further, the plant records requirement is necessary
16 in the likely event a subsequent depreciation study will be conducted by MKEC
17 (or its members) to determine adjustments to WPK depreciation rates. Historic ad-
18 valorem tax records may be required (or desired) to appeal subsequent Kansas
19 Department of Revenue Assessments that MKEC or its members may believe
20 excessive.

21

22 **Southern Pioneer**

23

REDACTED

Direct Testimony of David N. Dittmore
Docket No. 06-MKEE-524-ACQ

- 1 1. Southern Pioneer agrees that it will not remit dividends to Pioneer, absent
2 Commission approval. This condition is contained within the proposed Service
3 Agreement between Southern Pioneer and Pioneer.
- 4 2. Southern Pioneer will pass a Board of Director Resolution declaring its intent to
5 combine Southern Pioneer with Pioneer, as soon as various issues surrounding the
6 combination have been resolved.
- 7 3. Pioneer will file a report every three years to inform Commission on the status of
8 the prospective combination. The Pioneer Board of Directors shall pass a
9 resolution prior to filing such report to acknowledge this continued commitment.
- 10 4. Both Pioneer and Southern Pioneer will state specifically that they agree to
11 operate Southern Pioneer as a non-profit entity.
- 12 5. Southern Pioneer will not object to Staff's use of TIER or DSC ratios in the
13 determination of any subsequent Southern Pioneer revenue requirement. The
14 intent of this provision is that Southern Pioneer's cost of capital determined for
15 ratemaking purposes shall not be higher than what such calculation would
16 produce if Southern Pioneer were a member-owned cooperative.
- 17 6. Southern Pioneer shall establish an Advisory Group consisting of WPK acquired
18 customers. The Advisory Group shall be representative of WPK's customer
19 classes including urban and rural representation and provide input on issues
20 impacting ratepayers.
- 21 7. Staff reserves the right to argue in subsequent rate proceedings that income tax
22 expense should be disallowed if Pioneer has not adequately evaluated issues
23 surrounding Southern Pioneer's corporate status, or if such steps toward achieving

REDACTED

Direct Testimony of David N. Dittmore
Docket No. 06-MKEE-524-ACQ

1 this goal have been inadequate, or that such regulatory treatment would not
2 violate IRS requirements.

3

4 Discussion: The election by Pioneer to form a taxable corporation is an issue that
5 Staff has struggled with. Staff believes that one of the primary benefits of this
6 transaction is the acquiring entities are member owned cooperatives. These
7 cooperative members share in the margins of the cooperative and are tax-exempt
8 entities, providing substantial benefits to ratepayers over investor owned utilities.
9 The election by Pioneer to establish a taxable entity denies these benefits to its
10 acquired WPK customers. Staff held meetings with Pioneer regarding this
11 election and issued discovery on this topic. Pioneer's response to KCC Staff
12 Request 61 (deemed confidential) supporting its decision to establish a taxable
13 "C" corporation is attached as Exhibit DND-3. I will summarize the points made
14 by Southern Pioneer in this response supporting its decision and also briefly
15 provide Staff's comments.

16

17

a. ** [REDACTED]

18

[REDACTED]

19

[REDACTED]

20

[REDACTED]

21

[REDACTED]

22

[REDACTED]

23

[REDACTED]

REDACTED

Direct Testimony of David N. Dittimore
Docket No. 06-MKEE-524-ACQ

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[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] **

Notwithstanding how quickly the distribution asset spin-down may occur, there is a fundamental difference of opinion between Pioneer and MKEC regarding the tax implications of this transaction on distribution members. Attached as Exhibit DND-4 (portions confidential) is a summary of a conversation held between Staff, MKEC and its outside tax expert²⁵. In summary, MKEC believes that the tax impacts on MKEC cooperatives will be minimal. Staff understands that tax implications from this transaction are not clear-cut and therefore offers no independent finding in this area. Staff is not convinced from evidence provided that Pioneer's tax-exempt status would be jeopardized if Pioneer incorporated WPK customers into the cooperative. However, Staff recommends that Southern Pioneer further address its concerns over the prospect for losing Pioneer's tax-exempt status if it were to establish Southern Pioneer as a member-owned cooperative in future filings as further discussed below.

²⁵ Staff summarized the conversation held with MKEC and submitted its memo for MKEC to make any edits and corrections it felt were appropriate. This exhibit contains those MKEC edits and corrections.

REDACTED

Direct Testimony of David N. Dittmore
Docket No. 06-MKEE-524-ACQ

1 b. ****** [REDACTED]
2 [REDACTED]
3 [REDACTED]
4 [REDACTED]
5 [REDACTED]
6 [REDACTED]
7 [REDACTED]
8 [REDACTED]

9 [REDACTED] ****** Staff is sympathetic to Pioneer's concerns in this regard, however
10 alternatives and changes to existing Pioneer by-laws should be fully evaluated.
11 The goal of this review is to identify any by-law changes that would meet
12 Pioneer's objectives as well as permit WPK customers to become cooperative
13 members.

14
15 c. ****** [REDACTED]
16 [REDACTED]
17 [REDACTED]
18 [REDACTED]
19 [REDACTED]
20 [REDACTED]
21 [REDACTED] ******

22

REDACTED

Direct Testimony of David N. Dittmore
Docket No. 06-MKEE-524-ACQ

1 d. Other Issues – Pioneer has identified a number of other issues that factored
2 into its decision to establish Southern Pioneer as a taxable “C”
3 corporation. These issues include: ** [REDACTED]
4 [REDACTED]
5 ** See the attached confidential response (Exhibit DND-3) for
6 Pioneer’s comprehensive explanation of these issues. Staff acknowledges
7 that certain of these items represent legitimate concerns, while others, such
8 as concern over ** [REDACTED] ** could easily be resolved by
9 ** [REDACTED]
10 [REDACTED] **

11
12 Due to the issues and concerns raised by Pioneer, Staff is reluctant, at this time, to
13 recommend that the Commission mandate cooperative membership for WPK
14 members acquired by Pioneer. However, Staff is not convinced that such a
15 combination could not be achieved in the future, nor that the issues raised by
16 Pioneer are insurmountable to achieving the goal of cooperative membership for
17 the WPK customers acquired by Pioneer.

18
19 As a result of these concerns, Staff has identified a number of unique conditions
20 applicable to Southern Pioneer. The goal of these provisions is to ensure Pioneer
21 continues to seek solutions that would enable it to offer cooperative membership
22 to WPK customers and to prevent the potential that Southern Pioneer operations
23 would subsidize the operations of Pioneer. Staff’s conditions would require that

REDACTED

Direct Testimony of David N. Dittmore
Docket No. 06-MKEE-524-ACQ

1 Southern Pioneer file a report with the Commission once every three years
2 identifying options and challenges to offering cooperative membership to WPK
3 customers. The report should also identify progress made to achieving this goal.
4 Staff reserves the right in future rate proceedings to deny income tax expense
5 recovery if it believes Pioneer has not thoroughly evaluated options and issues
6 surrounding opportunity to offer cooperative membership to WPK customers.

7
8 Staff's recommendations regarding the restriction of dividends is designed to
9 prevent Pioneer from extracting dividends that otherwise would be used to build
10 much-needed equity within the Southern Pioneer Corporation. Staff also
11 recommends that Southern Pioneer will not object to evaluating the appropriate
12 capital structure and revenue requirements based upon the use of such cooperative
13 financial measures such as the Times Interest Earned Ratio (TIER) and Debt
14 Service Coverage (DSC). The intent of this recommendation is to prevent
15 Southern Pioneer from arguing in future rate proceedings that the Commission is
16 prohibited from using these cooperative financial measures in establishing an
17 appropriate revenue requirement.

18
19 The advisory group requirement is designed to provide WPK ratepayers some
20 opportunity to provide input into management and operation of the corporation,
21 similar to opportunities available to member owned cooperatives.

22 **Q. Does this conclude your testimony?**

23 **A. Yes.**

CERTIFICATE OF SERVICE

09-MKEE-969-RTS

I, the undersigned, hereby certify that a true and correct copy of the above and foregoing Direct Testimony was served by electronically sending a link on this 19th day of October, 2009, to the following:

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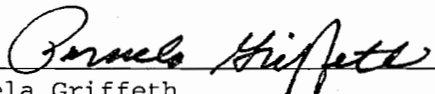
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Pamela Griffeth
Administrative Specialist

Exhibit LKB-6

Southern Pioneer's Response(s) to Data Request

Note: In an effort to conserve resources, Staff has excluded the voluminous portion of the DR response to CURB DR 12, not applicable to the particular discussion. Staff can provide the complete DR response upon request.

Staff Data Request No. 57

This Response contains Confidential Information

Staff Data Request No. 160

This Response Contains Confidential Information

**Kansas Corporation Commission
Information Request**

Request No: 198

Company Name

Docket Number 12-MKEE-380-RTS

Request Date March 30, 2012

Date Information Needed April 9, 2012

Please Provide the Following:

In Spec Hourly Loads spreadsheets provided with the responses to Staff DRS# 138 [2010 LAC billing demand data] and DR#183 [2011 billing demand data], there appears to be an error in the Tab "Hourly Loads", Column L (labeled as "Input to 34.5 less 3rd Party (A)"): Row L10 - a note stating "(1-2-3-4)", - seems to be indicating the formula should be subtracting values in Columns H through K from those in Column G. However, currently, the formula is not picking up Column J [National Beef] values at all, but is attempting to add empty row "K".

Row L10 - a note stating "(1-2-3-4)", - seems to be indicating the formula should be subtracting values in Columns H through K from those in Column G. However, currently, the formula is not picking up Column J [National Beef] values at all, but is attempting to add empty row "K".

Please, verify the formula for row L. If the error exists:

1. Identify what the corrected formula should be, apply the correction and re-submit the corrected Hourly Loads and Summary spreadsheets for both 2010 and 2011 data.

Answer: The correct formula should subtract columns H through J from column G as shown in this example: "=G11-SUM(H11:J11)".

2. In addition, for 2010 data - please, explicitly identify the total \$ amount, as well as the percentage change in LAC billing determinants and the resultant LAC rates (compared to what is currently in Company's direct testimony) resulting from this correction.

Answer: Please reference the table below. Please note that the formula correction identified above requires a re-determination of the LAC system CP date and time. I have separated the information into Total 34.5 kV and Schedule LAC. Due to the correction and a new system peak date and time the allocation between the retail and wholesale customers has changed.

	As Filed	Corrected	Change
Total 34.5 kV Revenue Requirements	\$3,439,611	\$3,439,611	0.0%
Total 34.5 kV Billing Determinants	1,294,746	1,061,430	-18.0%
Schedule LAC Revenue Requirements	\$1,021,470	\$1,283,329	25.6%
Schedule LAC Billing Determinants	384,011	396,089	3.1%
Schedule LAC Rate (\$/kW)	\$2.66	\$3.24	21.8%

3. Please, explain the reason loads for the "Air Products + Nat. Helium + Nat. Beef" <columns H through J> should be subtracted from the WHM on these SPEC Hourly Loads spreadsheets and specify the voltages these 3 customers are served off.

Answer: Instead of having 40+ columns of individual delivery points, the members load is already totaled for billing purposes. In the instance of Southern Pioneer there are three retail customers that are served from the 115kv transmission system (Air Products, National Helium, and National Beef. In order to get back to the actual load on the 34.5kv facilities these three customers have to be deducted out.

Submitted By Elena Larson

Submitted To Richard Macke

If for some reason, the above information cannot be provided by the date requested, please provide a written explanation of those reasons.

Verification of Response

I have read the foregoing Information Request and answer(s) thereto and find answer(s) to be true, accurate, full and complete and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request.

Signed:

Richard J. Mack

Date:

4/9/12

Southern Pioneer Electric Company
Summary of Local Access Billing Demands (kW) -- 2010

<u>Line</u>	<u>Description</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov</u>	<u>Dec</u>	<u>Total</u>
1	Total Local Access System ¹	82,317	77,973	70,204	69,464	85,465	114,174	118,581	115,342	111,227	79,676	79,237	74,137	1,077,798
2	CP Date	07	08	24	07	29	22	14	02	15	07	29	01	
3	CP Time (hour Ending) CST	2000	2000	2000	1100	1700	1600	1600	1600	1600	1600	1900	2100	
4														
5	Wholesale Customers @ Del. Pt.													
6	Ashland (KMEA)--Metered	1,980	1,917	1,647	1,729	2,155	3,357	3,638	3,740	3,267	2,095	1,693	1,772	28,989
7	Ashland (KMEA)--Generation	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Subtotal--Ashland	1,980	1,917	1,647	1,729	2,155	3,357	3,638	3,740	3,267	2,095	1,693	1,772	28,989
9	Kingman (KPP) Reservation	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	72,000
10	Kingman (KPP) Generation ²	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Subtotal--Kingman	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	72,000
12	Greensburg (KPP)	2,729	2,374	1,698	1,651	1,704	2,373	2,518	2,432	2,108	1,593	1,847	1,709	24,736
13	Greensburg Wind Farm (KPP)	10,408	10,787	10,718	11,845	8,498	9,325	7,776	4,880	9,253	3,608	11,741	10,583	109,421
14	Isabel (AR)	314	293	252	281	243	296	247	269	321	305	273	272	3,367
15	KEPCO	14,047	13,006	10,703	10,414	13,637	14,391	13,600	15,409	16,789	14,040	11,122	10,416	157,576
16	Subtotal--Wholesale	35,478	34,376	31,017	31,920	32,237	35,743	33,779	32,730	37,738	27,642	32,675	30,753	396,089
17	Losses @ 1.86% of 34.5 kV Output	355	327	266	262	330	380	372	406	418	335	278	264	3,993
18	Subtotal with Losses (@ Source)	35,833	34,704	31,283	32,182	32,567	36,123	34,152	33,136	38,156	27,977	32,952	31,016	400,082
19														
20	Southern Pioneer Retail													
21	Retail with Losses (@ Source)	46,484	43,270	38,920	37,282	52,897	78,051	84,429	82,206	73,071	51,699	46,285	43,121	677,716
22	Losses @ 1.83% of 34.5 kV Input	849	790	711	681	966	1,425	1,542	1,501	1,334	944	845	787	12,375
23	Retail @ Delivery Point	45,635	42,480	38,209	36,601	51,931	76,626	82,888	80,705	71,737	50,755	45,439	42,333	665,340

¹ Reference Workpaper

² January and February CP is 2011 as customer was not online during these months in 2010.

**Southern Pioneer Electric Company
 Summary of Local Access Billing Demands (kW) -- 2011**

<u>Line</u>	<u>Description</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov</u>	<u>Dec</u>	<u>Total</u>
1	Total Local Access System ¹	81,461	86,484	69,464	68,647	88,810	111,813	114,574	119,141	109,389	86,942	74,298	84,268	1,095,290
2	CP Date	31	01	08	09	30	16	20	24	01	03	08	05	
3	CP Time (hour Ending) CST	1900	2000	2100	1700	1700	1600	1600	1600	1600	1700	1900	1900	
4														
5	Wholesale Customers @ Del. Pt.													
6	Ashland (KMEA)--Metered	1,992	2,149	1,649	1,220	2,109	3,372	1,244	3,274	3,413	2,080	1,441	2,112	26,055
7	Ashland (KMEA)--Generation	-	-	-	-	-	-	2,723	446	-	-	-	-	3,169
8	Subtotal--Ashland	1,992	2,149	1,649	1,220	2,109	3,372	3,967	3,720	3,413	2,080	1,441	2,112	29,224
9	Kingman (KPP) Reservation	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	72,000
10	Kingman (KPP) Generation ²	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Subtotal--Kingman	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	72,000
12	Greensburg (KPP)	2,316	2,550	1,590	1,229	1,643	2,116	2,762	2,632	2,481	1,521	1,702	2,079	24,619
13	Greensburg Wind Farm (KPP)	10,676	11,354	9,411	10,826	5,620	11,004	1,370	5,803	6,573	9,433	11,929	11,316	105,314
14	Isabel (AR)	100	117	76	65	123	182	227	177	202	189	64	85	1,608
15	KEPCO	11,300	11,775	9,549	10,446	15,271	16,862	13,206	17,055	11,828	11,681	10,516	11,002	150,491
16	Subtotal--Wholesale	32,384	33,945	28,275	29,785	30,766	39,536	27,531	35,387	30,498	30,903	31,652	32,594	383,256
17	Losses @ 1.86% of 34.5 kV Output	292	309	239	241	356	419	375	439	333	288	255	284	3,831
18	Subtotal with Losses (@ Source)	32,676	34,253	28,515	30,026	31,122	39,955	27,906	35,825	30,831	31,191	31,907	32,878	387,086
19														
20	Southern Pioneer Retail													
21	Retail with Losses (@ Source)	48,785	52,230	40,950	38,621	57,688	71,857	86,668	83,316	78,558	55,751	42,390	51,389	708,204
22	Losses @ 1.83% of 34.5 kV Input	891	954	748	705	1,053	1,312	1,583	1,521	1,434	1,018	774	938	12,932
23	Retail @ Delivery Point	47,895	51,277	40,202	37,916	56,634	70,545	85,085	81,795	77,124	54,733	41,616	50,451	695,272

¹ With "behind the meter" generation, excluding Kingman, added back in.

² Exclude Kingman generation since MKEC does not have the transmission capacity to cover the full load.

Citizens' Utility Ratepayer Board
Information Request

Request No: CURB-12

Company Name MID-KANSAS AND SOUTHERN PIONEER

Docket Number 12-MKEE-380-RTS

Request Date January 19, 2012

Date Information Needed February 2, 2012

Please Provide the Following:

Please provide a copy of the loan documents that identify and describe all covenants and/or coverage requirements for the new CoBank loan.

Response:

See CURB 12 – A01, CURB 12 – A02 and CURB 12 – A03

Submitted By C. Steven Rarrick

Submitted To Mark Calcara

If for some reason, the above information cannot be provided by the date requested, please provide a written explanation of those reasons.

VERIFICATION OF RESPONSE

I have read the foregoing Data Request and Answer(s) thereto and find the answer(s) to be true, accurate, full and complete and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Citizens' Utility Ratepayer Board any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Data Request.

Signed: *Randall D. Magnus*
Name: Randall D. Magnus
Position: Executive VP - Assistant CEO
Dated: 02/02/2012

CREDIT AGREEMENT

by and between

SOUTHERN PIONEER ELECTRIC COMPANY, a Kansas corporation

and

CoBank, ACB, a federally chartered instrumentality of the United States

Dated as of: October 24, 2011

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7.11 Issuance of Stock. The Company shall not, and shall not permit any of its Subsidiaries to, issue any additional membership interests or shares of its capital stock or any options, warrants or other rights in respect thereof, except as may be required by Law or its Organizational Documents as in effect as of the date of this Agreement.

7.12 Changes in Organizational Documents. The Company shall not, and shall not permit any of its Subsidiaries to, amend in any respect its Organizational Documents (including any provisions or resolutions relating to capital stock), without, in the event such change would be adverse to CoBank as determined in its sole discretion, obtaining the prior written consent of CoBank. The Company shall and shall cause each other Loan Party to take such actions as CoBank may reasonably request to protect the Lcn of CoBank in the Collateral or otherwise to protect the interests of CoBank as a lender hereunder, as a result in either case of any change in an Organizational Document.

7.13 Anti-Terrorism Laws. Neither the Company nor any Subsidiary shall be (i) a Person with whom CoBank is restricted from doing business under Executive Order No. 13224 or any other Anti-Terrorism Law, (ii) engaged in any business involved in making or receiving any contribution of funds, goods or services to or for the benefit of such a Person or in any transaction that evades or avoids, or has the purpose of evading or avoiding, the prohibitions set forth in any Anti-Terrorism Law, or (iii) otherwise in violation of any Anti-Terrorism Law. The Company shall and shall cause each of the other Loan Parties to provide to CoBank any certifications or information that CoBank requests to confirm compliance by the Loan Parties and their Subsidiaries with any Anti-Terrorism Law.

7.14 Prepayment of Other Indebtedness. The Company will not, and will not allow any Subsidiary to, prepay Indebtedness owing to another lender while any Event of Default or Potential Default exists.

7.15 Wholesale Power Contracts; Material Agreements. The Company will not amend, alter or waive in any material respect any provision of a Wholesale Power Agreement or Material Agreement or breach or terminate a Wholesale Power Contract or Material Agreement or accept any breach or termination thereof by the counterparty. In addition, the Company will not consent to any assignment of a Wholesale Power Agreement or Material Agreement.

7.16 Generating Assets. The Company will not, and will not allow any Subsidiary to, purchase or construct any generating assets or acquire an interest in a Person that owns or intends to acquire any generating assets.

7.17. Option to Purchase. Enter into any new agreement respecting the acquisition or servicing of assets acquired or to be acquired by MKEC or any other Person, or enter into any Wholesale Power Contract without, in each case, the prior written consent of CoBank, which consent will not be unreasonably withheld.

ARTICLE 8. Financial Covenants. The Company covenants and agrees that until Payment In Full, the Company and each other Loan Party shall be in compliance at all times with the following covenants:

8.1 Debt Service Coverage Ratio. The Company (on both a consolidated and an unconsolidated basis) will have at the end of each fiscal quarter of the Company, a Debt Service Coverage Ratio for the twelve month period ending with the end of such quarter of not less than 1.35 to 1.00.

8.2 Equity to Total Assets Ratio. The Company (on an unconsolidated basis) will have at the end of each fiscal quarter shown below, an Equity to Total Assets Ratio of not less than the ratio shown next to such quarter:

FISCAL QUARTER ENDING:	REQUIRED RATIO (Equal to or greater than)
9/30/2011 through 6/30/2013	0
9/30/2013 through 12/31/2014	2%
3/31/2015 through 12/31/2016	5%
3/31/2017 through 12/31/2018	8%
3/31/2019 through 12/31/2019	11%

ARTICLE 9. Default

9.1 Events of Default. An Event of Default shall mean the occurrence or existence of any one or more of the following events or conditions (whatever the reason therefor and whether voluntary, involuntary, or effected by operation of Law) (each an “Event of Default”):

(a) **Payments Under Loan Documents.** The Company shall fail to pay any principal, interest, fee, or other amount owing hereunder or under any other Loan Document as and when due, whether by acceleration or otherwise, and such failure shall continue for five (5) Business Days.

(b) **Breach of Representation or Warranty.** Any opinion, certificate or like document furnished to CoBank by or on behalf of a Loan Party, or any representation or warranty made or deemed made at any time by any of the Loan Parties herein or in any other Loan Document shall be false or misleading in any material respect as of the time it was made or deemed made.

(c) **Breach of Negative Covenants or Certain Affirmative Covenants.** Any Loan Party shall default in the observance or performance of any covenant in Articles 7 or 8 hereof or any Loan Party shall default in the observance or performance of Sections 6.1(h)(i), 6.6, 6.8, 6.10 or any other covenant pertaining to the maintenance of insurance, visitation or inspection rights, compliance with Laws, or use of proceeds.

(d) **Breach of Other Covenants.** Any of the Loan Parties shall default in the observance or performance of any other covenant, condition, or provision hereof, and such default shall continue unremedied for a period of thirty (30) calendar days.

(e) **Cross Default.** Any Loan Party should, after any applicable grace period, breach or be in default under the terms of any other Loan Document (including, without limitation, any security instrument or document) or any other agreement between such Loan Party and CoBank (including the Southern Pioneer Guaranty) or between the Loan Party and any Affiliate of CoBank, including Farm Credit Leasing Services Corporation.

(f) **Defaults in Indebtedness to Other Lenders.** Any Loan Party or any Subsidiary of a Loan Party should default under the terms of any other agreement involving borrowed money or the extension of credit or any other Indebtedness under which any Loan Party or Subsidiary of any Loan Party may be obligated as a borrower or guarantor, or any other event occurs which, under any agreement or instrument relating to such indebtedness or obligation, has the effect of accelerating or permitting the

EXHIBIT A

DEFINITIONS AND RULES OF CONSTRUCTION

A. Defined Terms. In this Agreement, capitalized terms not otherwise defined herein shall have the respective meanings ascribed to them by the Notes and the following words and terms shall have the respective meanings set forth below:

"Affiliate" means, with respect to any Person, any other Person (i) which directly or indirectly controls, is controlled by, or is under common control with such Person, (ii) which beneficially owns or holds 5% or more of any class of the voting or other equity interests of such Person, or (iii) 5% or more of any class of voting interests or other equity interests of which is beneficially owned or held, directly or indirectly, by such Person. Each of Farm Credit Leasing Services Corporation and CoBank, FCB are **"Affiliates"** of CoBank for all purposes under this Agreement.

"Agreement" shall have the meaning set forth in the introductory paragraph hereof and shall include all amendments hereto.

"Anti-Terrorism Law" means any Law relating to terrorism or money laundering, including Executive Order No. 13224, the USA Patriot Act, the Laws comprising or implementing the Bank Secrecy Act, and the Laws administered by the United States Treasury Department's Office of Foreign Asset Control, as any of the foregoing Laws may from time to time be amended, renewed, extended, or replaced.

"Aquila" means Aquila, Inc. and its successors and assigns.

"Authorized Officer" means an officer or other individual duly authorized to execute Loan Documents on behalf of CoBank or the Company or any Loan Party, as the case may be, as designated from time to time in the case of any Loan Party on forms supplied or approved by CoBank.

"Business Day" means a day that is not a Saturday, a Sunday, or a day on which CoBank's principal office in Greenwood Village, Colorado, is closed pursuant to authorization or requirement of Law and, if the applicable Business Day relates to a Loan to which the Quoted Rate Option applies, such day must also be a day on which the Federal Reserve Bank of New York (or any successor) is open.

"Capital Lease" shall mean a lease which should be capitalized on the books of the lessee in accordance with GAAP.

"CFC" shall mean the National Rural Utilities Cooperative Finance Corporation and its successors and assigns.

"Closing Date" means the Business Day on which the first Loan or Letter of Credit is made or issued hereunder.

"CoBank" shall have the meaning set forth in the introductory paragraph of the Agreement and shall include its successors and assigns.

"CoBank Base Rate" means a fluctuating rate per annum equal at all times to the rate of interest established by CoBank from time to time as its CoBank Base Rate, which rate is intended by CoBank to be a reference rate and not its lowest rate. The CoBank Base Rate will change on the date established by

CoBank as the effective date of any change therein. CoBank's determination of the CoBank Base Rate shall be conclusive and binding upon the Company absent manifest error.

"CoBank Equities" is defined at Subsection 6.2(a).

"Code" means the Internal Revenue Code of 1986, as the same may be amended or supplemented from time to time, and any successor statute of similar import, and the rules and regulations thereunder, as from time to time in effect.

"Collateral" is defined at Section 6.3.

"Commitment" shall mean any commitment contained herein or in any other Credit Document to make Loans or issue Letters of Credit to or for the account of the Company.

"Company" shall have the meaning set forth in the introductory paragraph of the Agreement and shall include its permitted successors and assigns (if any).

"Company Acquisition Agreement" shall mean all agreements between MKEC and the Company relating to the acquisition by the Company of a portion of the assets to be acquired by MKEC from Aquila, as each may be amended or restated from time to time.

"Compliance Certificate" is defined at Subsection 6.1(c).

"Credit Facilities" is defined at ARTICLE 2.

"Debt Service Coverage Ratio" shall mean the ratio of: (1) the difference between (i) net income (after taxes and after eliminating any gain or loss on sale of assets or other extraordinary gain or loss), plus depreciation expense, amortization expense, and interest expense; minus (ii) non-cash patronage and non-cash income from joint ventures; to (2) all principal payments due within the period on all Long-Term Debt plus interest expense (all as calculated for the twelve month period ending with the end of the quarter in which the calculation is being made in accordance with GAAP consistently applied).

"Distribution" shall mean: (1) the payment of any dividend or distribution of any kind to its members, stockholders, or other owners, whether in cash, assets, obligations or otherwise; (2) the acquisition or retirement of any stock, membership or other interest in the Company; and (3) any rebate or reduction in rates that has the same effect.

"Effective Date" shall mean the date on which all conditions precedent set forth herein shall have been satisfied.

"Environmental Laws" means all applicable Laws issued by or entered into with an Official Body pertaining or relating to: (i) pollution or pollution control; (ii) protection of human health from exposure to hazardous or regulated substances; (iii) protection of the environment or natural resources; (iv) employee safety in the workplace; (v) the presence, use, management, generation, manufacture, processing, extraction, treatment, recycling, refining, reclamation, labeling, packaging, sale, transport, storage, collection, distribution, disposal, or release or threat of release of hazardous or regulated substances; (vi) the presence of contamination; (vii) the protection of endangered or threatened species; or (viii) the protection of environmentally sensitive areas.

"Equity" shall mean margins and equities of the Company as determined in accordance with GAAP on an unconsolidated basis.

“Equity to Total Assets Ratio” shall mean, as of any point in time, a ratio of Equity to Total Assets.

“ERISA” means the Employee Retirement Income Security Act of 1974, as the same may be amended or supplemented from time to time, and any successor statute of similar import, and the rules and regulations thereunder, as from time to time in effect.

“ERISA Affiliate” means, at any time, any trade or business (whether or not incorporated) under common control with the Company and treated as a single employer under Section 414 of the Code.

“ERISA Event” means (a) a reportable event (under Section 4043 of ERISA) with respect to a Plan; (b) a withdrawal by the Company or any ERISA Affiliate from a Plan subject to Section 4063 of ERISA during a plan year in which it was a substantial employer (as defined in Section 4001(a)(2) of ERISA) or a cessation of operations that is treated as such a withdrawal under Section 4062(e) of ERISA; (c) a complete or partial withdrawal by the Company or any ERISA Affiliate from a Multiemployer Plan or notification that a Multiemployer Plan is in reorganization; (d) the filing of a notice of intent to terminate, the treatment of a Plan amendment as a termination under Sections 4041 or 4041A of ERISA, or the commencement of proceedings by the PBGC to terminate a Plan or Multiemployer Plan; (e) an event or condition which constitutes grounds under Section 4042 of ERISA for the termination of, or the appointment of a trustee to administer, any Plan or Multiemployer Plan; or (f) the imposition of any liability under Title IV of ERISA, other than for PBGC premiums due but not delinquent under Section 4007 of ERISA, upon the Company or any ERISA Affiliate.

“Event of Default” means any of the events or conditions described in ARTICLE 9 and referred to therein as an “Event of Default.”

“Excluded Taxes” means (a) taxes imposed on or measured by the overall net income of CoBank (however denominated), and franchise taxes imposed on CoBank (in lieu of net income taxes), by the jurisdiction (or any political subdivision thereof) under the Laws of which CoBank is organized or in which its principal office is located or in which its applicable lending office is located, and (b) any branch profits taxes imposed by the United States of America or any similar tax imposed by any other jurisdiction in which the Company is located.

“Existing Credit Facilities” is defined at ARTICLE 2.

“Existing Line of Credit Supplement” shall mean the Amended and Restated Promissory Note and Supplement (Line of Credit) dated as of January 27, 2011, as amended, and numbered RX0435SO1C.

“Existing RUS Loans” means all loans made by RUS to the Company and outstanding on the date hereof.

“Existing Term Loans” is defined at Section 2.2.

“Existing Term Loan Notes” is defined at Subsection 2.2(a).

“Existing Term Loan Supplements” shall mean the following Promissory Notes and Supplements, as each may have been amended: (1) Promissory Note and Supplement (Single Advance Term Loan) No. RX0435T1 dated as of July 11, 2006; and (2) Promissory Note and Supplement (Single Advance Term Loan To Finance Eligible Capital Expenditures) No. RX0435T02 dated as of April 27, 2011.

“Fixed Rate Period” shall mean the period during which a Loan is fixed at a fixed rate, whether pursuant to the Quoted Rate Option or otherwise.

“GAAP” means generally accepted accounting principles in the United States of America in effect from time to time and consistently applied from period to period.

“Guaranty” is defined at Section 4.1(a)(viii).

“Indebtedness” means any and all indebtedness, obligations, or liabilities (whether matured or unmatured, liquidated or unliquidated, direct or indirect, absolute or contingent, or joint or several) for or in respect of: (i) borrowed money, (ii) amounts raised under or liabilities in respect of any note purchase or acceptance credit facility, (iii) any letter of credit or any bankers or trade acceptance arrangement, (iv) obligations under any Interest Rate Hedge, or under any currency, commodity, or other swap agreement or other hedging or risk management device, (v) any other transaction (including forward sale or purchase agreements, Capital Leases, or conditional sales agreements) having the commercial effect of a borrowing of money (but not including trade payables or accrued expenses incurred in the ordinary course of business which are not represented by a promissory note or other evidence of indebtedness and which are not more than sixty (60) days past due), or (vi) any guarantee of Indebtedness.

“Indemnified Taxes” means Taxes other than Excluded Taxes.

“Indemnitee” is defined at Subsection 10.2(b).

“Interest Rate Hedge” means any interest rate exchange, collar, cap, swap, adjustable strike cap, adjustable strike corridor or similar agreement.

“Interest Rate Option” means, for any Note, the interest rate options set forth in that Note.

“IRS” means the Internal Revenue Service.

“Law” means any law (including common law), constitution, statute, treaty, regulation, rule, ordinance, opinion, release, ruling, order, injunction, writ, decree, bond, judgment, consent, authorization, approval, lien or award of or by, or any settlement agreement with, any Official Body.

“Letter of Credit” is defined at Subsection 2.1(d).

“Letter of Credit Obligations” shall mean the sum of: (1) the maximum amount capable of being drawn on all outstanding Letters of Credit; plus (2) the aggregate amount of all unreimbursed payments and disbursements made by CoBank under the Letters of Credit.

“Letter of Credit Reimbursement Agreement” is defined at Subsection 2.1(e).

“Lien” means any mortgage, deed of trust, pledge, lien, security interest, charge or other encumbrance or security arrangement of any nature whatsoever, whether voluntarily or involuntarily given, including any conditional sale or title retention arrangement, and any assignment, deposit arrangement or lease intended as, or having the effect of, security and any filed financing statement or other notice of any of the foregoing (whether or not a lien or other encumbrance is created or exists at the time of the filing).

“Loan” means, unless the context indicates otherwise, each Loan as such term is defined in each Note.

“Loan Documents” means this Agreement and each Note, Guaranty, Letter of Credit, application, Interest Rate Hedge, and each other agreement, guaranty, security agreement, pledge, mortgage, deed of trust, instrument, agreement, certificate, application, and document executed or delivered in connection herewith or therewith.

“Loan Party” and **“Loan Parties”** shall mean the Company and each Person furnishing a guarantee of the Obligations.

“Loan Request” has the meaning set forth in each Note.

“Long-Term Debt” shall mean all Indebtedness having a maturity of more than one year from the date of its creation or having a maturity within one year from such date but that is renewable or extendible, at the Company’s option, to a date more than one year from such date or that arises under a revolving credit or similar agreement that obligates the lender(s) to extend credit during a period of more than one year from such date, including all current maturities in respect of such indebtedness whether or not required to be paid within one year from the date of its creation.

“Master Loan Agreement” has the meaning set forth in the Background paragraph of this Agreement.

“Material Adverse Change” means any set of circumstances or events which (i) has or could reasonably be expected to have any material adverse effect whatsoever upon the validity or enforceability of this Agreement or any other Loan Document, (ii) is or could reasonably be expected to be material and adverse to the business, properties, assets, financial condition, results of operations, or prospects of the Loan Parties taken as a whole, (iii) impairs materially or could reasonably be expected to impair materially the ability of the Loan Parties taken as a whole to duly and punctually pay or perform any of the Obligations, or (iv) impairs materially or could reasonably be expected to impair materially the ability of CoBank, to the extent permitted, to enforce its legal remedies pursuant to this Agreement or any other Loan Document.

“Material Agreement” means the Services Agreement, the Pioneer Services Agreements, and any other contract or other agreement (other than a Wholesale Power Contract) which, if breached or terminated, could reasonably be expected to result in a Material Adverse Change.

“MKEC” means Mid-Kansas Electric Company.

“MKEC Acquisition Agreement” means agreements between MKEC and Aquila relating to the acquisition of assets by MKEC from Aquila, as each may be amended or restated from time to time.

“Mortgage” shall mean: (1) until the New Mortgage has been executed, the Mortgage And Amended and Restated Security Agreement dated as of March 28, 2007, among the Company, National Cooperative Services Corporation, and CoBank; (2) upon the execution of the New Mortgage, the New Mortgage, as same may be amended and restated from time to time.

“Multiemployer Plan” means any employee benefit plan which is a “multiemployer plan” within the meaning of Section 4001(a)(3) of ERISA and to which the Company or any ERISA Affiliate is then making or accruing an obligation to make contributions or, within the preceding five Plan years, has made or had an obligation to make such contributions.

“NCSC” shall mean National Cooperative Services Corporation and its successors and assigns.

"NCSC Guaranty" shall mean that certain Guaranty from the Company to NCSC guaranteeing MKEC's outstanding loan balance and credit facility with NCSC.

"New Credit Facilities" is defined at ARTICLE 2.

"New Mortgage" is defined at Section 6.15 hereof.

"Note" means each promissory note issued in connection with this Agreement at any time or times.

"Obligations" means all obligations, indebtedness, and liabilities to CoBank, or any Subsidiary or Affiliate of CoBank, of any nature whatsoever arising at any time and from time to time including those arising under this Agreement, the Notes, the Letter of Credit Reimbursement Agreement, any application, or any other Loan Document and including those arising under Interest Rate Hedges or agreements governing other financial services or products provided by CoBank or one of its Subsidiaries or Affiliates to the Company or any other Loan Party.

"Official Body" means the government of the United States of America or any other nation or tribe, or of any political subdivision thereof, whether state, local, tribal or territorial, and any agency, authority, instrumentality, regulatory body, court, central bank or other entity exercising executive, legislative, judicial, taxing, regulatory, or administrative powers or functions of or pertaining to government and any group or body charged with setting financial accounting or regulatory capital rules or standards (including, without limitation, the Financial Accounting Standards Board, the Bank for International Settlements or the Basel Committee on Banking Supervision or any successor or similar authority to any of the foregoing).

"Organizational Documents" shall mean the instruments and documents under which a Person is organized or is operated, including a certificate or articles of incorporation, bylaws, certificate of limited partnership, partnership agreement, certificate of formation, limited liability company agreement, or other organizational document.

"Other Taxes" means all present or future stamp or documentary taxes or any other excise or property taxes, charges, or similar levies arising from any payment made under this Agreement, any Note, or any other Loan Document or from the execution, delivery, or enforcement of, or otherwise with respect to, this Agreement, any Note, or any other Loan Document.

"Participant" is defined at Section 10.6.

"Payment in Full" means the completion of the transactions hereunder and the indefeasible payment in full in cash of all Obligations hereunder, termination of all Commitments and the expiration or termination of all Letters of Credit issued in connection herewith.

"PBGC" means the Pension Benefit Guaranty Corporation established pursuant to Subtitle A or Title IV of ERISA or any successor.

"Permitted Encumbrances" shall have the meaning set forth in the Mortgage.

"Permitted Liens" is defined at Section 7.2.

"Person" means any individual, sole proprietorship, partnership, limited liability company, joint venture, trust, unincorporated organization, association, corporation, institution, public benefit corporation, firm, joint stock company, estate, entity or governmental agency.

"Personal Property Collateral" is defined at Section 6.3.

"Pioneer" shall mean Pioneer Electric Cooperative, Inc.

"Pioneer Consent and Agreement" means that certain Consent and Agreement dated as of July 11, 2006, among the Company, Pioneer, and CoBank, as same may be amended or restated from time to time.

"Pioneer Loan Documents" means that certain Credit Agreement dated as of October 24, 2011, between CoBank and Pioneer, all "Loan Documents" (as defined therein), and all amendments thereto and restatements thereof.

"Pioneer Services Agreement" means that certain Services Agreement dated as of July 7, 2006, between the Company and Pioneer, as same may be amended or restated from time to time.

"Plan" means at any time an employee pension benefit plan (including a Multiple Employer Plan, but not a Multiemployer Plan) subject to Title IV of ERISA or Section 412 of the Code or Section 302 of ERISA and in respect of which the Company or any ERISA Affiliate is (or if such plan were terminated, would under 4069 of ERISA be deemed to be) an "employer" as defined in Section 3(S) of ERISA.

"Potential Default" means any event or condition which with notice or passage of time, or both, would constitute an Event of Default.

"Quoted Rate" shall mean a fixed rate per annum to be quoted by CoBank in its sole discretion in each instance.

"Quoted Rate Option" means the Company's option under any Note to have Loans under a Credit Facility bear interest at the Quoted Rate.

"Real Property Collateral" is defined at Section 6.3.

"Relief Proceeding" is defined at Subsection 9.1(l).

"Revolver Expiration Date" is defined at Section 2.1(a).

"Revolving Commitment" is defined at Section 2.1(a).

"Revolving Credit Facility" is defined at Section 2.1.

"Revolving Credit Note" is defined at Section 2.1(a).

"Revolving Loan" is defined at Section 2.1(a).

"RUS" shall mean the Rural Utilities Service of the US Department of Agriculture or any successor thereto.

"Services Agreement" shall mean the Electric Customer Service Agreement dated as of July 2, 2007, as same may be amended or restated from time to time.

"Single Advance Commitment Expiration Date" is defined at Subsection 2.3(a).

"Single Advance Term Loan" is defined at Subsection 2.3(a).

"Single Advance Term Loan Commitment" is defined at Subsection 2.3(a).

"Single Advance Term Note" is defined at Subsection 2.3(b).

"Statements" is defined at Section 5.5.

"Subsidiary" means a corporation, trust, partnership, limited liability company, or other business entity (a) of which shares of stock or similar interests having ordinary voting power to elect a majority of the board of directors, trustees, or other managers of such entity (regardless of any contingency which does or may suspend or dilute the voting rights) are owned or controlled, directly or indirectly, by the Company or one of its Subsidiaries, or (b) which is directly or indirectly controlled or capable of being controlled by the Company or one or more of the Company's Subsidiaries.

"Sunflower" shall mean Sunflower Electric Cooperative and its successors and assigns.

"Taxes" means any present or future taxes, levies, imposts, duties, deductions, withholdings, assessments, fees, or other charges imposed by any Official Body, including any interest, additions to tax, or penalties applicable thereto.

"Total Assets" shall mean total assets of the Company as computed in accordance with GAAP.

"Total Debt" shall mean the sum of all Indebtedness.

"Tranche" means specified portions of the Loans of any one Credit Facility outstanding as follows: (i) any Loans to which the Quoted Rate Option applies under the same Loan Request by the Company and which have the same period shall constitute one Tranche, and (ii) all Loans to which the Variable Rate Option applies shall constitute one Tranche.

"2011 Multiple Advance Commitment Expiration Date" is defined at Subsection 2.4(a).

"2011 Multiple Advance Term Loans" is defined at Subsection 2.4(a).

"2011 Multiple Advance Term Loan Commitment" is defined at Subsection 2.4(a).

"2011 Multiple Advance Term Note" is defined at Subsection 2.4(b).

"Variable Rate" shall mean a rate per annum equal to the rate of interest established by CoBank on the first Business Day of each week in its sole discretion in each instance. The rate established by CoBank shall be effective until the first Business Day of the next week and each change in the rate shall be applicable to all balances subject to this option. Information about the then current rate shall be made available upon telephonic request.

"Variable Rate Option" means the Company's option under any Note to have Loans under a Credit Facility bear interest at the Variable Rate.

"Wholesale Power Contracts" shall mean all wholesale power contracts between the Company and its wholesale power suppliers, as each has been or may be amended, supplemented, or restated from time to time.

B. Rules of Construction. Unless the context of this Agreement otherwise clearly requires, the following rules of construction shall apply to this Agreement and each of the other Loan Documents: (i) references to the plural include the singular (and vice versa), and the words "include," "includes," and "including" shall be deemed to be followed by the phrase "without limitation"; (ii) the words "hereof," "herein," "hereunder," "hereto," and similar terms in this Agreement or any other Loan Document refer to this Agreement or such other Loan Document as a whole; (iii) references to any article, section, subsection, clause, schedule, and exhibit are references to this Agreement or other Loan Document, as the case may be, unless otherwise specified, and all exhibits and schedules are incorporated herein by reference; (iv) reference to any Person includes such Person's successors and assigns; (v) reference to any document, instrument, or agreement, including this Agreement and any other Loan Document together with the schedules and exhibits hereto or thereto, means such document, instrument, or agreement as amended, restated, replaced, refinanced, supplemented, substituted, increased, extended, superseded, or otherwise modified from time to time; (vi) relative to the determination of any period of time, "from" means "from and including," "to" means "to but excluding," and "through" means "through and including;" (vii) the words "asset" and "property" shall be construed to have the same meaning and effect and to refer to any and all tangible and intangible assets and properties, including cash, securities, accounts and contract rights; (viii) section headings herein and in each other Loan Document are included for convenience and shall not affect the interpretation of this Agreement or such Loan Document; (ix) references to any Loan Document or any other document, instrument, or agreement is deemed to include a reference to all annexes, schedules, and exhibits thereto, and (x) unless otherwise specified, all references herein to times of day shall be references to prevailing Denver time.

C. Accounting Principles. Except as otherwise provided in this Agreement, all computations and determinations as to accounting or financial matters and all financial statements to be delivered pursuant to this Agreement shall be made and prepared in accordance with GAAP (including principles of consolidation where appropriate), and all accounting or financial terms shall have the meanings ascribed to such terms by GAAP; provided, however, that all accounting terms used in Article 8 (and all defined terms used in the definition of any accounting term used in such Article) shall have the meaning given to such terms (and defined terms) under GAAP as in effect on the date hereof applied on a basis consistent with those used in preparing the Statements referred to in Article 5. In the event of any change after the date hereof in GAAP, and if such change would affect the computation of any of the financial covenants set forth in Article 8, then the parties hereto agree to endeavor, in good faith, to agree upon an amendment to this Agreement that would adjust such financial covenants in a manner that would preserve the original intent thereof, but would allow compliance therewith to be determined in accordance with the Company's financial statements at that time, provided that, until so amended, such financial covenants shall continue to be computed in accordance with GAAP prior to such change therein.

**FIRST AMENDMENT TO
CREDIT AGREEMENT**

THIS FIRST AMENDMENT TO CREDIT AGREEMENT (the "Agreement") is dated as of December 19, 2011, and is entered into by and between **SOUTHERN PIONEER ELECTRIC COMPANY**, a Kansas corporation (the "Company"), and **COBANK, ACB**, a federally chartered instrumentality of the United States ("CoBank").

BACKGROUND

CoBank and the Company are parties to a Credit Agreement dated as of October 24, 2011 (the "Credit Agreement"). The parties now desire to amend the Credit Agreement.

NOW, THEREFORE, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

SECTION 1. Definitions. Capitalized terms used in this Amendment and not defined herein shall have the meanings given to those terms in the Credit Agreement.

SECTION 2. Amendment. Section 8.1 of the Credit Agreement is hereby amended and restated to read as follows:

8.1 Debt Service Coverage Ratio. The Company (on both a consolidated and an unconsolidated basis) will have at the end of each fiscal quarter of the Company set forth below, a Debt Service Coverage Ratio for the twelve month period ending with the end of such quarter of not less than the ratio set forth next to such quarter:

FISCAL QUARTER ENDING:	REQUIRED RATIO (Equal to or greater than)
12/31/2011	1.05
12/31/2012 and each fiscal quarter thereafter	1.35

Notwithstanding the foregoing, in the event the Kansas Corporation Commission approves new ratemaking methodology based upon the Company's Debt Service Coverage Ratio, then in lieu of the Debt Service Coverage Ratio required above for the fiscal quarter ending on December 31, 2012 and each fiscal quarter thereafter, the Company shall have the following Debt Service Coverage Ratios for such quarters:

FISCAL QUARTER ENDING:	REQUIRED RATIO (Equal to or greater than)
12/31/2012	1.00
3/31/2013 and 6/30/2013	1.10
9/30/2013 and 12/31/2013	1.25
3/31/2014 through 12/31/2015	1.35

In the event the Kansas Corporation Commission approves such new ratemaking methodology, then the Company shall furnish written notice thereof to CoBank together with a copy of the order approving the new methodology.

SECTION 3. Representations and Warranties. To induce CoBank to enter into this Amendment, the Company represents and warrants that: (A) no consent, permission, authorization, order or license of any governmental authority or of any party to any agreement to which the Company is a party or by which it or any of its property may be bound or affected, is necessary in connection with the execution, delivery, performance or enforcement of this Amendment; (B) the Company is in compliance with all of the terms of the Loan Documents, and no Potential Default or Event of Default exists; and (C) this Amendment has been duly authorized, executed and delivered, and creates legal, valid, and binding obligations of the Company which are enforceable in accordance with their terms, except to the extent that enforceability may be limited by applicable bankruptcy, insolvency or similar Laws affecting the rights of creditors generally. Without limiting (B) above, the Company represents and warrants that it is in compliance with all notice provisions of the Credit Agreement, including, without limitation, the requirement to notify CoBank of the commencement of material litigation and of certain environmental matters.

SECTION 4. Confirmation. Except as amended hereby, the Supplement shall remain in full force and effect as written.

IN WITNESS WHEREOF, the parties hereto have executed this Amendment by their duly authorized officers as of the date first set forth above.

COBANK, ACB

By: 

Shannon Davoren

Name: _____

Assistant Corporate Secretary

Title: _____

SOUTHERN PIONEER ELECTRIC COMPANY

By: 

Name: Randall D. Magnison

Title: Executive VP-Assistant CEO

PIONEER ELECTRIC COOPERATIVE, INC. hereby acknowledges the above amendment and confirms that the amendment shall not affect its liability under the Guarantee of Payment dated as of October 24, 2010, which shall remain in full force and effect as written

PIONEER ELECTRIC COOPERATIVE, INC.

By: 

Name: Stephen J. Epperson

Title: Chief Executive Officer

KANSAS ELECTRIC POWER COOPERATIVE, INC.

Information Request

Request No.1-26

Company Name MID-KANSAS ELECTRIC COMPANY, LLC
Docket Number 12-MKEE-380-RTS
Request Date February 3, 2012
Date Information Needed February 17, 2012
RE: MKEC's Application of December 20, 2011

Please provide the following:

With reference to the Macke Direct, p. 25, ll. 14-22, provide the MPSC order in the reference Case No. U-6652.

Response: Please see the attached file 'KEPCO_0026.pdf'.

Submitted By KEPCo
Submitted To MKEC

If for some reason, the above information cannot be provided by the date requested, please provide a written explanation of those reasons.

Verification of Response

I have read the foregoing Information Request and answer(s) thereto and find the answer(s) to be true, accurate, full and complete and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to KEPCo any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request.

Signed: Richard J. Mack
Date: 2-17-12

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of)
ONTONAGON COUNTY RURAL ELECTRIFICATION)
ASSOCIATION for authority to file,)
establish and make effective increased)
rates for the sale of electric energy.)

Case No. U-6652

At a session of the Michigan Public Service Commission held at its offices
in the City of Lansing, Michigan, on the 10th day of February, 1981.

PRESENT: Hon. Daniel J. Demlow, Chairperson
Hon. Eric J. Schneidewind, Commissioner
Hon. Edwyna G. Anderson, Commissioner

OPINION AND ORDER

I.

HISTORY OF PROCEEDINGS

On October 28, 1980, Ontonagon County Rural Electrification Association
(Applicant) filed an application for authority to increase its rates and charges
for electric service.

Pursuant to due notice, a public hearing was held in the offices of the Com-
mission on January 6, 1981. Applicant presented the testimony of one witness and
offered six exhibits, including proposed rate schedules. The Commission Staff
(Staff) cross-examined Applicant's witness and presented the testimony of one
witness and offered two exhibits. On January 5, 1981, a petition to intervene
was filed by Eli Sironen but he did not appear at the hearing.

At the conclusion of the hearing, all parties waived compliance with the
provisions of Section 81 of the Administrative Procedures Act, 1969 PA 306, as
amended, MCLA 24.281.

II.

DESCRIPTION OF APPLICANT

Applicant is a Michigan nonprofit corporation with principal offices located at Ontonagon, Michigan and is engaged in the distribution and sale of electric energy in rural portions of Ontonagon, Houghton, Keweenaw and Baraga Counties. As of June 30, 1980, Applicant had 3,209 member-customers.

III.

THE TEST PERIOD

In this, as in other rate proceedings, it is necessary to select a test period and to adjust its results for known changes in revenues and expenses so that the adjusted operating results will be representative of the future, and thereby afford a reasonable basis upon which to predicate rates which will be effective subsequent to this order. In this proceeding, Applicant submitted testimony and exhibits covering the year ending June 30, 1980, adjusted for known cost increases occurring subsequent to that date.

There having been no evidence presented covering any other period and no objection having been made to the test period ending June 30, 1980, as adjusted, the Commission adopts it as the appropriate test period.

IV.

STATEMENT OF FACTS

The basic rates now being charged by Applicant for electric service were authorized by the Commission in its order dated December 11, 1979 in Case No. U-6223.

Applicant represents that because of unprecedented levels of inflation its

costs have increased while sales have been lower than anticipated. As a result, Applicant's operations have shown a loss in every month since the issuance of the Commission's order in Case No. U-6223. According to Exhibit A-2, on an unadjusted basis, Applicant's operations for the test period reflect a net loss of \$129,703. Applicant seeks authority to establish rates which produce additional revenues of \$118,762 annually.

Applicant and the Staff agree that the Rural Electrification Administration (REA) and the Cooperative Finance Corporation (CFC) require a Times Interest Earned Ratio (TIER) of between 1.5 and 2.5. The Commission order in Case No. U-6223 authorized revenues to yield a TIER at the minimum level of 2.43.

It appears that Applicant's financial condition is deteriorating to the point where REA funding is no longer assured. In processing Applicant's most recent loan application, REA felt compelled to establish special mechanisms because of Applicant's steadily deteriorating financial condition. As REA stated:

"Since December 31, 1974, your [Applicant's] system has been unable to earn a positive margin from its operations. Considering the financial condition of the cooperative, we believe that if Ontonagon is unable to place into effect timely rate increases which will insure adequate feasibility for REA loans, the cooperative should consider curtailing its construction program. System improvements will have to be drastically reduced. As a further step, REA is considering placing a special condition on the 'U-4' loan. The condition would require receipt of evidence that adequate retail rates have been approved and are effective before any 'U-4' loan funds could be released."

The Commission FINDS that to ensure continuous service and to accommodate system expansion and improvements an increase in Applicant's revenues is necessary and appropriate.

While Applicant's presently authorized rates are based on revenues designed to yield a 2.43 TIER, Applicant's \$118,762 request seeks an authorized TIER of 2.6. Applicant represents that a 3.0 TIER is more appropriate, but requests the 2.6 TIER as a first step toward that goal. For reasons discussed below, the

Commission need not address the propriety of raising Applicant's TIER levels.

Applicant indicates that its goal is to provide the best possible service at the lowest possible rates. Applicant represented that for that reason its retail rates have traditionally been lower than its major wholesale supplier, Upper Peninsula Power Company.

According to Exhibit A-2, Applicant's monthly expenses have consistently exceeded revenue, even after annualizing the impact of Applicant's last rate case (U-6223). Applicant indicates that these results and REA and CFC threshold interest coverage requirements have forced and will continue to force Applicant to seek repeated rate relief from this Commission.

The need for continuous rate review costs Applicant and its member-customers dearly. The Commission recognizes that rate cases are expensive affairs. Engineering and legal consultants are often hired and utility personnel invest countless hours in rate case preparation and trips to Lansing. For a cooperative located in the Upper Peninsula, regulatory expenses are even more burdensome. Especially for a utility the size of Applicant, with only 3,000 customers, rate case expense becomes a significant part of the rate relief awarded.

While this Commission's relief has been timely, there is always the unavoidable lag between the time a decision is made to seek relief and the time such relief is granted. Accordingly, in its filing, Applicant recommended a new mechanism, TIER Indexing, which it represents will reduce customer costs, decrease rate case expenses and allow Applicant to maintain revenue stability.

Mr. William J. Chabot, Applicant's General Manager, recommended TIER Indexing as an alternative to present ratemaking mechanisms. As Mr. Chabot explained, traditional mechanisms have been designed to authorize revenues which yield a TIER of approximately 2.5. When TIER fell to unacceptable levels, the cooperative would analyze its financial status, conduct a rate study, put together a detailed filing, and make application to the Commission for another rate increase.

The Commission, after a Staff evaluation, would again revise rates to yield a 2.5 target TIER. Because of economic conditions, the process repeats itself time after time.

Under TIER Indexing, as proposed by Applicant, revenues authorized herein would be designed to yield a lower TIER; to wit, approximately 2.4. In addition, Applicant would withdraw normalizing expense adjustments. The net effect of these changes would be to reduce Applicant's rate request by approximately 33%.

The next phase of TIER Indexing would occur after Applicant has experienced six months of operation under the base rate order. At this point, a review would be made to determine whether Applicant's TIER had increased or decreased from the 2.4 level authorized in the base rate order. If the six-month TIER level is between 2.0 and 2.8, there would be no adjustment in rates. If the six-month TIER level is greater than 2.8, an ex parte rate reduction would be made as necessary to bring TIER back to 2.4. If, on the other hand, TIER has fallen below 2.0, a hearing would be held to determine what revenue increase is necessary to bring TIER back to 2.4.

Once six more months of operations have been analyzed, the process would repeat itself. Applicant suggests that TIER Indexing be instituted as an experimental two-year program.

The Commission has reviewed Applicant's financial condition and the proposed TIER Indexing mechanism in depth. The Commission herein adopts, as an experimental two-year program, TIER Indexing, for the following reasons, among others:

1. Because TIER Indexing should allow Applicant to maintain revenue stability, rates established herein need not yield as high a TIER level. In the instant proceeding, this allows the rate increase authorized to be lower by a factor of approximately 33%.
2. In addition to substantial immediate reduction in member-customer rates, engineering and attorney fees should be markedly reduced, thus further reducing member-customer costs.

3. Because Applicant should be able to maintain revenue stability, financing costs should be lower, thus further reducing member-customer costs.
4. Once TIER Indexing has been established, Commission and Staff resources need not be expended, to the extent they have been in the past, in rate proceedings for Applicant.
5. The process, as detailed below, is simple, mechanically non-controversial and easy to understand.
6. The characteristics of a cooperative, being owned by its customers, uniquely adapt themselves to this type of mechanism. To the extent rates increase because of imprudent management, member-customers will seek answers. In addition, the Staff is expected to monitor expenditures to assure reliability of the mechanism. Finally, management will be expected to reduce, wherever possible, expenditures.

In short, the Commission believes that adoption of TIER Indexing as an experimental, two-year program is in the interest of Applicant and its member-customers.

In adopting TIER Indexing, the Commission cautions that it will carefully monitor Applicant's performance. While certain other cooperatives may, in the future, be authorized similar mechanisms, the Commission stresses that Applicant's size and financial condition, as detailed in the record, were carefully reviewed.

Applicant's proposed increase, with TIER Indexing, totaled \$79,706. Applicant's present fuel and purchased power adjustment clause contains two separate basing points, one for its Ewen and Trout Creek substations, and another for its main system. Applicant's filing did not request adjustments to those basing points. However, subsequent to its filing, Applicant learned of wholesale power increases scheduled to soon go into effect. The Staff accordingly suggested a 31.62 mills per Kwh base for customers served by Applicant's Ewen and Trout Creek substations, and a 40.63 mills per Kwh base for main system customers. Applicant did not object to those revised basing points.

The Staff recommended a \$79,706 increase. Applicant objected to neither the Staff's recommended revenue increase nor to its method of calculation. The Commission herein adopts the Staff's proposed revenue increase and adjustment clause

basing points.

The TIER Indexing mechanism which the Commission is adopting shall operate as follows:

1. By this order, Applicant will be authorized to place into effect, for service rendered on and after February 1, 1981, rates designed to produce an annual increase in revenues of approximately \$79,706.
2. By September 10, 1981, Applicant is directed to submit a calculation of its TIER for the six-month period ending July 31, 1981. If the calculated TIER is between 2.0 and 2.8, there need be no adjustment in rates. If the six-month TIER is greater than 2.8, Applicant should submit a calculation of revenue reductions necessary to bring TIER back to 2.4. If, on the other hand, TIER has fallen below 2.0, a hearing will be scheduled to determine what revenue increase is necessary to bring TIER back to 2.4.
3. Upon submission of Applicant's TIER analysis, the Staff is directed to review such calculations for methodology and accuracy. If no revenue increase is necessary, hearings need not be scheduled unless the Staff or Applicant specifically request such hearing.
4. Applicant's calculation of its six-month TIER shall be based on its unadjusted statement of operations, as reflected in its REA Form 7, with only three adjustments:
 - a. Rates established in this base rate order should be annualized.
 - b. Seasonal revenue, which Applicant traditionally collects in one month, should be normalized.
 - c. The lag in purchased power revenue should be adjusted, where necessary, so that the analysis coincides with actual levels.
5. At the conclusion of the above-described process, Applicant shall inform its member-customers as to the determination of the Commission, and method of calculation of revised rates, if necessary. If a revenue decrease or increase is authorized, such shall be handled through a per Kwh surcharge on customer bills in the first monthly bill following such order. In subsequent months, the surcharge shall be incorporated in customer energy rates.
6. By April 1982, financial statements covering a full 12-month period since the issuance of the base rate order should be available. If a hearing is necessary (i.e., if a revenue increase is necessary), the only adjustments that need be considered relate to purchased power revenue lag and annualization of the prior six-month rate order, if an increase was warranted.

7. The process will continue every six months thereafter, subject to review by this Commission after February 1, 1983.

The Commission FINDS that the TIER Indexing system established by this order should be subject to alterations, on application of Applicant or suggestion of the Staff or other parties. It would not be in the public interest to freeze the system so adjustments could not be made. The Commission is establishing an innovative program. In most innovative programs there are "bugs" which must be eliminated to make the program work properly. In addition, the long-run future is uncertain. The Commission simply must have the flexibility to deal directly with unanticipated serious problems. However, where Applicant requests a change in the TIER Indexing system, Applicant will have a heavy burden to demonstrate the necessity of the change.

Neither Applicant nor the Staff recommended changes in rate design. The Commission FINDS that the rate design established in its order in Case No. U-6223 should be maintained.

With two exceptions, there were no proposals to change Applicant's Rules and Regulations. The first exception related to a proposed amendment to Applicant's Rules and Regulations to allow Applicant to assess a late payment charge not in excess of 2%, not compounded, of the bill, net of taxes, for residential customers. In the Commission's order of October 28, 1980 in Case No. U-4240, revising the Consumer Standards and Billing Practices, it specifically allowed such change in Rule 18(2). The Staff proposed a second exception involving refunds of advances for construction. The Commission FINDS that those two amendments to Applicant's Rules and Regulations are reasonable and appropriate.

The Commission FINDS that:

- a. Jurisdiction is pursuant to 1909 PA 106, as amended, MCLA 460.551 et seq.; 1919 PA 419, as amended, MCLA 460.51 et seq.; 1939 PA 3, as amended, MCLA 460.1 et seq.; 1969 PA 306, as amended, MCLA 24.201 et seq.; and the

Commission's Rules of Practice and Procedure, 1954 Administrative Code, 1968 Annual Supplement, R 460.11 et seq.

b. Additional annual revenue of approximately \$79,706 will yield a TIER of 2.4 and enable Applicant to meet the financing requirements of its lending agencies.

c. A TIER Indexing system as set forth in this Opinion and Order is reasonable and should be adopted. The TIER Indexing system should be implemented by keeping the record open for the receipt of evidence and any necessary adjustment of rates, according to the terms and provisions set forth in this Opinion and Order.

d. Applicant's fuel and purchased power adjustment clauses as established in Case No. U-6223 and as developed in the Commission's bimonthly decisions should be retained, the new basing points being as set forth in this Opinion and Order.

e. The electric rate schedules attached hereto as Exhibit A will increase Applicant's annual electric operating revenues as authorized by this Opinion and Order and will result in just and reasonable rates and charges for the sale of electric energy and should be made effective for service rendered on and after March 1, 1981.

THEREFORE, IT IS ORDERED that:

A. Ontonagon County Rural Electrification Association is hereby authorized to place into effect, for service rendered on and after March 1, 1981, the Standard Rules and Regulations and rate schedules attached hereto as Exhibit A. The rates are designed to produce an increase in annual revenues of approximately \$79,706.

B. The record in this case is left open for the limited purpose of implementing the TIER Indexing mechanism according to the terms and procedures set

forth in this Opinion and Order.

C. Ontonagon County Rural Electrification Association shall continue to implement bimonthly purchased power cost adjustment hearings as set forth in this order.

D. Ontonagon County Rural Electrification Association shall, within 30 days, submit for filing six copies of the Standard Rules and Regulations and rate schedules substantially the same as those attached hereto as Exhibit A.

The Commission specifically reserves jurisdiction of the matters herein contained and the authority to issue such further order or orders as the facts and circumstances may require.

Any party desiring to appeal this order must perfect an appeal to the Ingham County Circuit Court within 30 days after issuance and notice of the order, pursuant to MCLA 460.301.

MICHIGAN PUBLIC SERVICE COMMISSION

/s/ Daniel J. Demlow
Chairperson

(S E A L)

/s/ Eric J. Schneidewind
Commissioner

Commissioner Edwyna G. Anderson dissents and is, this date, issuing the attached Dissenting Opinion.

By the Commission and pursuant to its action of February 10, 1981.

/s/ Thomas R. Lonergan
Its Secretary

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of)
ONTONAGON COUNTY RURAL ELECTRIFICATION)
ASSOCIATION for authority to file,)
establish and make effective increased)
rates for the sale of electric energy.)

Case No. U-6652

DISSENTING OPINION OF COMMISSIONER EDWYNA G. ANDERSON

(Submitted on February 10, 1981 concerning
order issued on same date)

Today Ontonagon County Rural Electrification Association (Ontonagon) is being granted a \$79,706 rate increase for electric service. Such an increase will add approximately 6.6% to the average 500 Kwh user's bill, raising it to a monthly base in excess of \$40.

A careful and complete review of all transcripts indicates that Ontonagon is in poor financial health and clearly in need of revenues generated by this Opinion and Order.

Ontonagon has been caught in a spiralling period of escalating costs and falling sales. During the test year ending June 30, 1980 Ontonagon lost \$129,703. Ontonagon's monthly expenses have consistently outstripped revenues in recent months.

Such data indicates to me that the patient is obviously sick and in need of an immediate remedy. Unfortunately, I cannot agree with the majority's remedy.

The majority has introduced another "innovative" program to cure this patient. The new program is called "TIER INDEXING." TIER is an acronym for "times interest

earned ratio." This ratio is computed by adding the earnings for the period plus interest expense and dividing by the interest expense.

The TIER measures the extent to which earnings can decline without resultant financial embarrassment to the firm because of inability to meet annual interest costs.

Nowhere is there any indication that the Rural Electrification Administration (REA) requires a minimum TIER of 2.0 to meet its standards. The bottom line of this TIER Indexing is to allow this co-op's earnings to vacillate between a 2.0 and a 2.8 TIER.

The majority argues that such innovation allows the Commission to grant a \$79,703 increase rather than a traditional rate increase running as high as \$118,672. TIER Indexing, according to the majority, further allows reduced expenses such as engineering and attorneys fees generated during rate hearings and should increase revenue stability, thereby lowering financing costs. The majority continues:

"5. The process, as detailed below is simple, mechanically noncontroversial and easy to understand." (Order, page 6)

In reality the TIER Indexing program is no more than a thinly-disguised Consumer Price Index (CPI) program. Ontonagon currently has a TIER ratio well below 2.0. They have taken a smaller piece of the cake (\$79,703) immediately to insure a larger piece (2.0 - 2.8 TIER ratio) in the future. Under this plan they will not come before this Commission unless their earnings exceed a TIER ratio of 2.8 or fall below a TIER ratio of 2.0.

Expense control and review by this Commission will be nonexistent so long as Ontonagon maintains a 2.0 - 2.8 TIER ratio.

If Ontonagon comes close to a 2.0 TIER ratio there is a tempting incentive to fall below such a ratio so as to immediately qualify for rate relief that will bring them back to a 2.4 TIER ratio. If, on the other hand, they start to approach a 2.8 TIER ratio there is an equally strong incentive to increase expenses so as to avoid Commission adjustment.

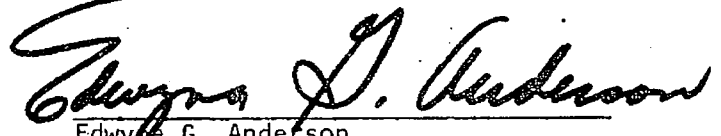
Again, the problem is simply an inability of this Commission to scrutinize, yes even regulate, this co-op. We have little or no ability to review alleged increases in relationship to overall revenues, revenue requirements, costs of service and other relevant factors relating to the co-op's fiscal condition.

I certainly agree that co-ops are unique and sometimes warrant special treatment. This may result from such factors as nonprofit capital structure and ownership by their members.

But one must wonder if Ontonagon's member/customers are aware of TIER Indexing and its rate implications.

Additionally, there is the persistent threat that the pervasive and pernicious practice of spreading these new programs to other companies will likely not stop here.

In summary, this Commission under the guise of "innovation" is adding another automatic adjustment program to its already overladen arsenal of "pass throughs." I cannot, nor will I, support such Indexing plans. I must respectfully dissent.


Edwyn G. Anderson
Commissioner

February 10, 1981
Lansing, Michigan

Exhibit LKB-7

CFC Key Ratio Trend Analysis

CFC KRTA

Pioneer Electric Cooperative, Inc.
KS044

PRODUCED BY: CFC
Woodland Park
2201 Cooperative Way
Herndon, VA 20171
1-800-424-2954

06/27/2011

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
BASE GROUP (RATIOS 1-5)																
RATIO 1 --- AVERAGE TOTAL CONSUMERS SERVED																
2006	15,550	12,605	818	351	5,554	27	3	17,492	99	87	6,949	6	2	8,336	110	24
2007	15,821	12,866	819	357	6,774	27	5	17,570	96	83	17,193	6	4	15,821	167	84
2008	16,141	13,166	818	357	6,820	27	5	17,629	95	77	17,398	6	4	22,296	83	52
2009	16,453	13,220	816	348	6,840	27	5	17,724	95	66	17,675	6	4	16,326	93	46
2010	16,606	13,250	815	348	6,869	27	5	17,580	92	62	17,825	6	4	10,913	33	11
RATIO 2 --- TOTAL KWH SOLD (1,000)																
2006	672,214	250,709	818	140	104,904	27	3	317,677	99	5	159,015	6	2	179,932	110	5
2007	709,990	267,135	819	141	110,048	27	3	318,922	96	4	474,542	6	2	331,803	167	29
2008	764,165	276,164	818	133	117,251	27	3	323,188	95	4	543,694	6	2	456,395	83	29
2009	796,604	273,002	816	122	115,102	27	3	314,542	95	4	537,798	6	2	333,602	93	22
2010	834,512	284,611	815	125	123,159	27	3	331,857	92	4	566,341	6	2	289,042	33	5
RATIO 3 --- TOTAL UTILITY PLANT (1,000)																
2006	80,652.61	52,313.13	819	257	28,891.54	27	3	66,460.11	99	21	41,017.46	6	2	38,002.76	110	13
2007	90,747.70	56,418.34	820	239	33,718.83	27	5	67,944.33	96	15	90,834.72	6	4	67,370.64	167	52
2008	105,632.17	59,850.53	819	219	34,049.82	27	4	72,828.37	95	6	103,703.59	6	3	92,801.64	84	41
2009	113,325.28	63,199.26	817	215	35,027.09	27	5	73,920.29	95	8	113,516.08	6	4	79,197.68	93	34
2010	124,533.26	66,306.87	816	201	36,709.65	27	4	81,073.74	92	6	122,682.94	6	3	58,316.90	33	8
RATIO 4 --- TOTAL NUMBER OF EMPLOYEES (FULL TIME ONLY)																
2006	56	46	815	324	31	27	3	58	98	52	44	6	2	33	110	21
2007	58	46	819	324	31	27	5	57	96	44	64	6	4	54	167	76
2008	63	47	818	293	32	27	5	56	95	33	71	6	4	75	83	45
2009	61	48	816	306	33	27	5	57	95	36	71	6	4	57	93	41
2010	64	47	815	283	34	27	5	57	92	27	71	6	4	46	33	9
RATIO 5 --- TOTAL MILES OF LINE																
2006	3,725	2,536	816	223	2,098	27	5	2,759	99	17	3,277	6	2	2,140	110	20
2007	3,760	2,550	819	224	2,141	27	6	2,742	96	16	3,645	6	3	2,901	167	48
2008	3,836	2,579	818	221	2,141	27	6	2,708	95	14	3,874	6	4	2,975	83	35
2009	3,892	2,594	816	216	2,136	27	6	2,719	95	13	3,904	6	4	2,664	93	28
2010	3,932	2,595	815	208	2,130	27	5	2,727	92	13	3,922	6	3	2,409	33	7
FINANCIAL (RATIOS 6-32)																
RATIO 6 --- TIER																
2006	2.21	2.29	819	441	2.29	27	15	2.35	99	59	2.04	6	3	2.57	110	68
2007	3.65	2.24	820	152	2.36	27	5	2.15	96	17	1.92	6	1	2.21	167	28
2008	1.53	2.27	819	692	1.93	27	22	2.06	95	82	1.39	6	3	2.14	84	70
2009	2.60	2.30	817	308	2.47	27	13	2.17	95	33	1.90	6	2	2.21	93	37
2010	3.35	2.45	816	207	2.40	27	7	2.38	92	28	2.07	6	1	2.59	33	10

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 7 --- TIER (2 OF 3 YEAR HIGH AVERAGE)																
2006	3.94	2.49	819	160	2.86	27	7	2.53	99	17	3.27	6	2	2.65	110	28
2007	3.75	2.40	820	166	2.81	27	6	2.48	96	19	2.84	6	2	2.43	167	29
2008	2.93	2.46	819	281	2.46	27	10	2.43	95	29	2.27	6	2	2.44	84	29
2009	3.13	2.48	817	246	2.61	27	7	2.38	95	27	2.26	6	1	2.56	93	32
2010	2.98	2.56	816	287	2.71	27	12	2.46	92	35	2.01	6	2	2.70	33	13
RATIO 8 --- OTIER																
2006	1.54	1.79	819	545	2.03	27	19	1.88	99	70	1.32	6	3	1.94	110	88
2007	2.90	1.73	820	134	1.87	27	6	1.64	96	15	0.74	6	1	1.72	167	26
2008	1.72	1.70	819	402	1.63	27	13	1.64	95	42	0.86	6	1	1.65	84	38
2009	2.35	1.71	817	208	1.76	27	7	1.69	95	26	1.20	6	2	1.71	93	27
2010	2.01	1.91	816	363	1.91	27	12	1.97	92	44	1.68	6	2	1.93	33	16
RATIO 9 --- OTIER (2 OF 3 YEAR HIGH AVERAGE)																
2006	3.56	1.99	819	115	2.25	27	5	2.05	99	14	2.87	6	2	2.10	110	18
2007	3.18	1.95	820	136	2.21	27	7	1.95	96	17	2.01	6	2	1.93	167	26
2008	2.31	1.93	819	256	2.09	27	11	1.90	95	32	1.41	6	2	1.95	84	28
2009	2.63	1.89	817	181	1.99	27	7	1.86	95	21	1.15	6	1	1.88	93	22
2010	2.18	1.95	816	301	1.97	27	8	1.89	92	34	1.54	6	2	2.02	33	15
RATIO 10 --- MODIFIED DSC (MDSC)																
2006	1.92	1.91	819	398	2.00	27	15	1.95	99	52	1.57	6	3	1.94	110	57
2007	2.51	1.86	820	193	1.90	27	7	1.86	96	28	2.20	6	3	1.86	167	35
2008	1.71	1.82	819	501	1.71	27	15	1.89	95	57	1.60	6	3	1.87	84	58
2009	2.31	1.85	817	210	1.70	27	5	1.89	95	30	1.86	6	2	1.86	93	25
2010	2.52	1.95	816	202	1.86	27	4	2.10	92	33	2.29	6	2	2.11	33	9
RATIO 11 --- MDSC (2 OF 3 YEAR HIGH AVERAGE)																
2006	2.72	2.02	819	186	2.21	27	7	2.04	99	23	2.50	6	3	2.07	110	25
2007	2.63	2.00	820	204	2.19	27	7	2.11	96	27	2.41	6	3	2.03	167	41
2008	2.22	1.98	819	309	2.08	27	10	1.98	95	37	1.95	6	3	2.07	84	33
2009	2.41	1.95	817	233	2.03	27	7	1.95	95	32	2.09	6	3	1.99	93	29
2010	2.42	2.00	816	242	1.95	27	6	2.07	92	33	2.21	6	3	2.21	33	13
RATIO 12 --- DEBT SERVICE COVERAGE (DSC)																
2006	1.81	2.11	819	556	2.00	27	18	2.15	99	71	1.63	6	3	2.15	110	76
2007	2.55	2.08	820	242	2.12	27	7	2.05	96	31	2.28	6	3	2.05	167	46
2008	1.52	2.07	819	715	2.08	27	23	1.96	95	81	1.92	6	5	2.09	84	76
2009	2.18	2.06	817	359	2.09	27	10	2.06	95	44	1.97	6	3	2.05	93	43
2010	3.13	2.21	816	151	2.26	27	3	2.30	92	27	2.56	6	1	2.21	33	9

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 13 --- DSC (2 OF 3 YEAR HIGH AVERAGE)																
2006	2.66	2.23	819	259	2.36	27	8	2.17	99	29	2.47	6	3	2.22	110	36
2007	2.62	2.22	820	257	2.36	27	8	2.33	96	33	2.72	6	4	2.24	167	48
2008	2.18	2.23	819	439	2.23	27	16	2.17	95	46	2.32	6	4	2.34	84	49
2009	2.36	2.23	817	341	2.27	27	11	2.20	95	38	2.41	6	4	2.31	93	44
2010	2.65	2.26	816	259	2.27	27	7	2.31	92	35	2.39	6	3	2.47	33	11
RATIO 14 --- ODSC																
2006	1.46	1.80	819	632	1.90	27	20	1.82	99	77	1.30	6	3	1.83	110	85
2007	2.17	1.75	820	233	1.74	27	8	1.74	96	30	1.56	6	1	1.75	167	45
2008	1.62	1.74	819	500	1.67	27	15	1.74	95	56	1.52	6	3	1.80	84	56
2009	2.04	1.77	817	270	1.64	27	6	1.84	95	35	1.82	6	2	1.81	93	32
2010	2.21	1.86	816	252	1.78	27	6	2.00	92	37	2.21	6	3	1.96	33	11
RATIO 15 --- ODSC (2 OF 3 YEAR HIGH AVERAGE)																
2006	2.47	1.93	819	212	2.12	27	7	1.98	99	27	2.13	6	3	1.94	110	26
2007	2.33	1.91	820	238	2.04	27	6	1.96	96	32	2.07	6	2	1.92	167	50
2008	1.89	1.87	819	400	1.90	27	15	1.90	95	49	1.64	6	3	1.98	84	47
2009	2.10	1.86	817	286	1.99	27	11	1.89	95	38	1.81	6	3	1.90	93	34
2010	2.13	1.90	816	296	1.90	27	8	1.97	92	38	2.04	6	3	2.07	33	16
RATIO 16 --- EQUITY AS A % OF ASSETS																
2006	52.28	42.01	819	210	42.02	27	9	43.25	99	28	36.40	6	2	46.40	110	39
2007	48.60	41.14	820	255	41.27	27	8	42.46	96	36	21.59	6	1	42.28	167	53
2008	47.09	40.62	819	282	40.14	27	9	41.85	95	35	21.81	6	1	38.74	84	24
2009	45.29	41.26	817	314	39.53	27	10	42.15	95	39	21.87	6	1	39.37	93	31
2010	42.51	41.78	816	390	40.98	27	11	43.69	92	50	21.14	6	1	35.95	33	12
RATIO 17 --- DISTRIBUTION EQUITY (EXCLUDES EQUITY IN ASSOC. ORG'S PATRONAGE CAPITAL)																
2006	52.17	36.38	819	159	39.69	27	8	36.39	99	21	34.73	6	2	41.33	110	26
2007	48.49	35.78	820	188	38.03	27	6	35.73	96	25	21.35	6	1	36.52	167	41
2008	46.94	34.91	819	196	36.49	27	8	35.56	95	24	21.51	6	1	33.10	84	20
2009	45.13	35.11	817	209	35.69	27	8	34.80	95	24	21.56	6	1	31.68	93	24
2010	42.34	35.87	816	263	35.95	27	9	35.39	92	31	20.80	6	1	31.99	33	9
RATIO 18 --- EQUITY AS A % OF TOTAL CAPITALIZATION																
2006	55.07	47.27	819	280	46.83	27	11	49.30	99	38	42.47	6	2	52.74	110	48
2007	58.36	47.26	820	217	47.27	27	7	48.92	96	31	38.49	6	1	48.59	167	45
2008	53.06	47.22	819	300	44.22	27	9	47.58	95	37	30.64	6	1	44.01	84	26
2009	54.68	47.63	817	263	45.23	27	7	48.18	95	34	30.96	6	1	45.08	93	29
2010	49.64	48.60	816	389	47.35	27	11	49.67	92	47	28.28	6	1	45.66	33	14

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 19 ---- LONG TERM DEBT AS A % OF TOTAL ASSETS																
2006	42.65	45.87	813	480	44.50	27	16	44.26	99	55	44.38	6	5	42.60	108	54
2007	34.68	46.13	813	625	45.52	27	20	45.43	95	68	46.84	6	5	45.08	166	125
2008	41.66	45.44	811	491	46.78	27	19	45.18	94	57	59.69	6	5	46.90	83	54
2009	37.53	45.69	808	575	45.99	27	20	45.50	92	65	61.71	6	5	46.81	92	64
2010	43.13	44.72	807	446	46.88	27	18	44.42	89	50	57.65	6	6	45.69	33	23
RATIO 20 ---- LONG TERM DEBT PER KWH SOLD (MILLS)																
2006	56.32	91.99	813	612	109.01	27	22	89.91	99	74	87.37	6	5	86.27	108	77
2007	50.75	93.80	813	650	112.83	27	24	93.70	95	72	89.57	6	6	88.94	166	129
2008	57.90	96.00	811	620	120.34	27	24	92.75	94	70	85.68	6	6	90.62	83	67
2009	54.79	103.19	808	648	136.31	27	25	100.33	92	72	91.88	6	6	102.20	92	76
2010	69.17	103.16	807	570	124.23	27	25	100.77	89	61	105.52	6	6	103.23	33	27
RATIO 21 ---- LONG TERM DEBT PER CONSUMER (\$)																
2006	2,434.59	1,777.28	813	191	1,905.77	27	7	1,598.12	99	14	2,431.69	6	3	1,774.35	108	31
2007	2,277.28	1,862.81	813	264	1,838.03	27	9	1,627.90	95	16	2,366.92	6	4	1,843.93	166	50
2008	2,741.15	1,932.21	811	171	2,063.99	27	8	1,704.63	94	10	2,531.76	6	3	1,998.97	83	19
2009	2,652.70	2,043.37	808	218	2,180.30	27	8	1,862.56	92	12	2,582.57	6	3	2,262.12	92	32
2010	3,476.12	2,063.99	807	95	2,235.49	27	5	1,946.24	89	7	2,986.50	6	3	2,640.97	33	8
RATIO 22 ---- NON-GOVERNMENT DEBT AS A % OF TOTAL LONG TERM DEBT																
2006	23.87	28.11	791	438	16.10	23	9	32.78	97	55	5.17	6	2	32.78	103	59
2007	21.97	27.77	786	459	21.97	23	12	32.08	94	58	41.47	6	4	28.96	161	95
2008	15.34	26.90	786	543	16.93	23	13	28.19	94	67	38.57	6	4	25.09	82	55
2009	15.40	25.26	792	504	14.21	23	11	22.66	91	57	4.55	6	2	23.56	91	59
2010	16.24	32.80	794	631	31.19	23	16	28.03	89	63	1.45	5	2	37.43	32	25
RATIO 23 ---- BLENDED INTEREST RATE (%)																
2006	5.36	5.13	813	269	4.82	27	7	5.19	98	35	4.58	6	2	5.11	108	37
2007	5.17	5.19	813	418	4.86	27	11	5.28	94	63	5.40	6	5	5.18	166	86
2008	4.60	5.12	811	664	4.86	27	16	5.15	93	80	4.15	6	3	5.01	83	66
2009	4.73	5.07	809	597	4.75	27	16	5.12	92	74	4.09	6	2	5.01	92	69
2010	5.08	4.96	807	337	4.87	27	9	5.01	89	40	4.33	6	2	5.02	33	15
RATIO 24 ---- ANNUAL CAPITAL CREDITS RETIRED PER TOTAL EQUITY (%)																
2006	4.68	2.17	638	63	1.31	27	3	1.94	77	3	1.80	6	1	2.12	91	9
2007	2.36	2.02	649	271	0.98	27	8	1.75	75	30	1.17	6	2	1.90	136	58
2008	2.37	2.05	634	265	1.13	27	5	1.89	74	28	0.48	6	1	1.42	57	15
2009	2.15	1.95	631	282	0.68	26	5	1.78	77	28	0.35	6	1	1.78	66	24
2010	3.75	1.99	653	107	0.78	27	3	1.91	76	8	0.35	6	1	1.71	29	2

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 25 --- LONG-TERM INTEREST AS A % OF REVENUE																
2006	4.23	5.15	813	539	4.89	27	20	4.98	98	63	4.31	6	4	4.88	108	69
2007	3.80	5.27	813	588	5.31	27	20	5.09	94	65	4.31	6	4	5.06	166	115
2008	3.28	5.06	811	629	4.72	27	22	4.87	93	72	3.64	6	4	4.99	83	63
2009	3.51	5.14	809	596	5.34	27	23	4.99	92	66	4.84	6	5	5.12	92	64
2010	3.98	4.87	807	524	5.36	27	23	4.82	89	56	4.90	6	5	5.43	33	24
RATIO 26 --- CUMULATIVE PATRONAGE CAPITAL RETIRED AS A % OF TOTAL PATRONAGE CAPITAL																
2006	34.45	24.46	698	166	23.76	25	6	20.73	83	10	25.25	6	2	25.44	98	27
2007	33.63	24.89	695	189	23.38	25	6	21.64	79	14	24.50	6	2	26.00	143	41
2008	34.86	24.61	695	160	23.09	26	6	22.20	80	13	26.28	6	2	20.57	70	11
2009	34.63	24.59	696	159	22.44	25	6	22.43	81	13	25.11	6	2	23.29	76	9
2010	34.55	24.61	696	164	21.89	24	6	21.56	79	13	25.72	6	2	24.16	30	8
RATIO 27 --- RATE OF RETURN ON EQUITY (%)																
2006	5.29	6.51	819	527	6.95	27	17	6.20	99	63	4.94	6	3	6.48	110	74
2007	10.24	7.03	820	159	8.28	27	6	6.26	96	14	9.72	6	3	6.85	167	20
2008	2.05	6.82	819	752	6.49	27	23	6.70	95	85	1.75	6	3	6.63	84	78
2009	6.63	7.10	817	451	8.21	27	19	6.72	95	50	7.71	6	5	6.89	93	53
2010	11.09	7.62	816	146	7.85	27	5	7.68	92	15	10.35	6	3	9.96	33	8
RATIO 28 --- RATE OF RETURN ON TOTAL CAPITALIZATION (%)																
2006	5.32	5.82	819	504	5.93	27	17	5.61	99	62	4.71	6	3	5.91	110	70
2007	8.22	6.04	820	118	5.86	27	3	5.66	96	10	6.00	6	1	5.98	167	13
2008	3.13	5.99	819	769	5.78	27	24	5.98	95	87	2.99	6	3	5.69	84	79
2009	5.88	6.01	817	429	6.25	27	19	5.79	95	43	5.35	6	3	5.88	93	47
2010	7.85	6.22	816	158	6.35	27	3	6.35	92	16	6.63	6	1	6.94	33	8
RATIO 29 --- CURRENT RATIO																
2006	3.32	1.29	819	64	1.59	27	4	1.14	99	2	1.65	6	1	1.51	110	7
2007	1.36	1.21	820	345	0.88	27	9	1.20	96	37	1.15	6	2	1.23	167	75
2008	1.17	1.16	819	408	1.05	27	11	1.16	95	47	0.97	6	1	0.97	84	35
2009	0.65	1.20	817	697	0.84	27	19	1.19	95	81	0.70	6	4	1.10	93	78
2010	0.68	1.23	816	704	0.90	27	18	1.14	92	81	0.69	6	4	1.07	33	25
RATIO 30 --- GENERAL FUNDS PER TUP (%)																
2006	27.40	3.99	819	22	4.51	27	2	4.39	99	4	9.16	6	2	4.93	110	3
2007	15.38	3.91	820	62	3.96	27	3	4.24	96	7	4.80	6	2	4.68	167	13
2008	13.97	3.91	819	86	3.19	27	3	4.12	95	8	3.22	6	2	3.24	84	10
2009	15.94	3.72	817	56	2.53	27	3	3.98	95	7	4.54	6	2	4.01	93	5
2010	16.59	4.16	816	53	2.73	27	3	4.28	92	7	3.82	6	2	2.20	33	3

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 31 ---- PLANT REVENUE RATIO (PRR) ONE YEAR																
2006	6.47	6.39	819	378	6.97	27	19	6.25	99	40	6.72	6	5	6.31	110	45
2007	5.99	6.37	820	533	7.08	27	24	6.27	96	63	8.43	6	6	6.30	167	109
2008	7.79	6.44	819	106	7.10	27	9	6.30	95	9	8.18	6	6	6.46	84	14
2009	7.13	6.46	817	224	7.08	27	13	6.32	95	15	7.86	6	5	6.46	93	27
2010	7.25	6.31	816	187	6.70	27	11	6.02	92	13	7.26	6	4	6.67	33	12
RATIO 32 ---- INVESTMENT IN SUBSIDIARIES TO TOTAL ASSETS (%)																
2006	2.59	0.53	257	52	1.57	10	3	0.58	27	5	1.47	4	1	0.34	25	7
2007	0.64	0.52	251	119	1.27	11	8	0.38	23	10	1.47	4	4	0.73	56	30
2008	0.59	0.67	246	128	1.96	9	9	0.40	23	11	0.83	3	3	0.41	32	15
2009	0.15	0.57	239	161	2.08	9	8	0.26	24	15	0.61	3	3	0.37	38	27
2010	0.78	0.61	246	116	2.30	10	8	0.44	24	10	1.60	4	3	0.31	12	4
REVENUE & MARGINS (RATIOS 33-59)																
RATIO 33 ---- TOTAL OPERATING REVENUE PER KWH SOLD (MILLS)																
2006	71.51	88.12	818	674	105.89	27	27	90.55	99	85	89.46	6	6	85.67	110	89
2007	72.25	91.18	819	691	102.88	27	27	93.29	96	85	84.19	6	6	86.20	167	142
2008	76.88	97.15	818	688	111.75	27	27	99.21	95	86	90.37	6	6	94.81	83	70
2009	77.89	100.87	816	702	110.45	27	27	103.39	95	87	87.11	6	6	100.90	93	81
2010	81.10	102.30	815	706	116.66	27	27	103.08	92	84	95.61	6	6	98.89	33	27
RATIO 34 ---- TOTAL OPERATING REVENUE PER TUP INVESTMENT (CENTS)																
2006	59.60	40.76	819	111	37.18	27	2	43.27	99	13	42.15	6	1	38.98	110	13
2007	56.53	41.13	820	136	34.34	27	2	43.69	96	16	43.82	6	1	41.50	167	31
2008	55.62	42.13	819	183	36.22	27	3	44.64	95	25	47.79	6	2	44.00	84	23
2009	54.75	42.05	817	168	34.36	27	1	44.59	95	21	44.63	6	1	43.75	93	24
2010	54.34	42.52	816	189	37.04	27	2	44.74	92	26	49.00	6	1	37.04	33	7
RATIO 35 ---- TOTAL OPERATING REVENUE PER CONSUMER (\$)																
2006	3,091.11	1,724.30	818	57	1,804.52	27	3	1,627.07	99	4	2,629.35	6	2	1,725.17	110	12
2007	3,242.36	1,797.89	819	52	1,754.80	27	2	1,656.69	96	2	2,423.38	6	2	1,820.45	167	10
2008	3,639.64	1,921.74	818	51	1,849.83	27	1	1,842.99	95	1	2,743.55	6	1	1,990.25	83	1
2009	3,771.08	1,981.84	816	46	1,848.04	27	1	1,926.52	95	2	2,584.21	6	1	2,020.39	93	4
2010	4,075.48	2,114.03	815	41	2,066.79	27	1	1,997.03	92	2	2,853.52	6	1	2,278.00	33	2
RATIO 36 ---- ELECTRIC REVENUE PER KWH SOLD (MILLS)																
2006	71.22	86.75	818	669	104.09	27	27	87.53	99	85	89.07	6	6	84.42	110	90
2007	71.98	89.17	819	681	100.23	27	26	90.18	96	84	83.90	6	6	84.77	167	140
2008	76.62	95.42	818	675	108.69	27	27	96.22	95	85	90.06	6	6	92.39	83	68
2009	77.66	98.81	816	695	109.68	27	27	99.83	95	87	85.09	6	6	98.23	93	78
2010	80.87	100.25	815	700	114.48	27	27	99.58	92	84	92.21	6	6	95.67	33	27

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 37 --- ELECTRIC REVENUE PER CONSUMER (\$)																
2006	3,078.60	1,686.67	818	52	1,799.58	27	2	1,588.82	99	4	2,623.52	6	2	1,698.10	110	12
2007	3,230.10	1,761.38	819	50	1,731.19	27	2	1,636.21	96	2	2,414.99	6	2	1,780.90	167	10
2008	3,627.52	1,883.20	818	46	1,835.01	27	1	1,811.01	95	1	2,706.41	6	1	1,930.03	83	1
2009	3,760.18	1,940.25	816	41	1,749.75	27	1	1,877.49	95	2	2,553.27	6	1	2,003.63	93	4
2010	4,064.25	2,068.08	815	37	1,957.77	27	1	1,957.23	92	2	2,750.35	6	1	2,187.50	33	2
RATIO 38 --- RESIDENTIAL REVENUE PER KWH SOLD (MILLS)																
2006	94.75	94.46	817	401	110.64	27	23	95.36	99	51	105.23	6	6	95.53	110	59
2007	94.13	96.40	819	450	108.07	27	24	97.39	96	55	103.83	6	6	93.50	167	83
2008	93.97	102.30	818	554	115.02	27	26	103.83	95	66	109.71	6	6	99.15	83	50
2009	94.92	107.21	816	595	115.93	27	25	109.28	95	75	100.44	6	6	107.26	93	68
2010	97.69	109.01	815	582	124.13	27	27	108.22	92	68	108.71	6	6	103.37	33	23
RATIO 39 --- NON-RESIDENTIAL REVENUE PER KWH SOLD (MILLS)																
2006	68.98	76.82	816	535	95.75	27	26	78.82	99	73	83.65	6	6	79.82	110	74
2007	69.92	79.10	818	562	91.43	27	26	82.59	96	73	79.09	6	6	76.37	167	107
2008	75.14	85.43	817	564	99.32	27	26	87.41	95	66	85.30	6	6	80.34	83	58
2009	76.23	88.28	815	596	94.24	27	24	86.11	95	70	80.76	6	5	89.98	93	72
2010	79.45	89.78	814	580	99.92	27	26	88.53	92	66	87.84	6	6	85.70	33	20
RATIO 41 --- IRRIGATION REVENUE PER KWH SOLD (MILLS)																
2006	91.59	93.86	400	210	117.86	18	14	93.87	40	23	90.08	6	3	95.93	64	36
2007	94.28	100.32	399	233	125.82	18	14	99.09	41	28	93.03	6	3	102.58	75	48
2008	94.40	111.11	397	274	131.62	18	15	112.67	42	33	93.82	6	3	111.25	34	26
2009	99.53	117.82	398	284	130.48	18	16	118.39	42	34	101.89	6	4	110.47	41	29
2010	103.98	124.98	394	290	126.41	18	17	123.11	42	31	106.86	6	5	93.00	19	7
RATIO 42 --- SMALL COMMERCIAL REVENUE PER KWH SOLD (MILLS)																
2006	89.80	86.43	814	344	104.77	27	23	89.80	99	50	95.43	6	5	88.66	110	52
2007	90.08	88.67	817	376	100.62	27	22	90.72	96	52	93.92	6	5	87.04	167	69
2008	88.56	95.09	816	502	106.89	27	24	97.30	95	69	98.29	6	5	92.85	83	51
2009	88.96	99.12	813	575	107.26	27	24	100.56	95	75	94.69	6	5	100.56	93	70
2010	91.80	100.47	813	556	112.66	27	25	101.61	92	70	102.61	6	5	103.39	33	23
RATIO 43 --- LARGE COMMERCIAL REVENUE PER KWH SOLD (MILLS)																
2006	53.20	61.53	673	473	67.87	16	15	62.42	89	71	63.50	4	4	59.29	88	57
2007	54.60	63.98	680	500	75.86	18	17	65.59	88	72	72.10	5	5	60.82	147	103
2008	62.44	69.03	684	445	77.22	19	16	69.70	88	63	77.22	5	5	63.19	70	37
2009	62.40	72.21	685	478	76.84	18	14	69.44	88	63	64.03	5	4	68.88	71	49
2010	65.04	72.94	683	472	79.75	19	15	70.91	85	56	79.09	5	5	68.36	27	17

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 44 ---- SALES FOR RESALE REVENUE PER KWH SOLD (MILLS)																
2006	57.87	51.56	114	45	57.82	9	4	57.87	11	6	59.60	4	4	53.13	16	5
2007	56.87	54.82	113	48	51.06	9	3	56.46	9	4	57.79	4	3	56.02	21	9
2008	60.85	58.36	117	57	54.35	9	3	57.94	9	4	62.33	4	3	51.85	9	4
2009	54.55	61.86	121	90	52.96	8	4	61.48	9	7	57.47	4	3	55.80	12	8
2010	55.65	64.14	119	88	58.16	8	5	62.96	9	9	61.49	4	3	55.65	9	5
RATIO 45 ---- STREET & HIGHWAY LIGHTING REVENUE PER KWH SOLD (MILLS)																
2006	160.98	119.66	589	156	125.00	20	4	110.78	63	14	114.97	5	1	106.49	74	12
2007	171.00	124.36	587	146	132.68	21	3	113.41	61	10	157.69	6	1	112.78	111	26
2008	171.15	132.71	586	163	144.25	21	4	126.98	61	16	169.43	6	2	147.86	63	25
2009	177.95	139.11	588	156	149.57	22	3	128.56	61	12	158.85	6	1	163.48	61	22
2010	183.01	142.73	587	159	148.42	22	4	133.93	62	14	157.68	6	1	146.83	22	4
RATIO 47 ---- OPERATING MARGINS PER KWH SOLD (MILLS)																
2006	1.56	2.94	818	589	4.70	27	21	2.78	99	73	0.96	6	3	3.20	110	92
2007	5.14	2.99	819	196	5.02	27	12	2.40	96	15	-1.12	6	1	2.63	167	25
2008	1.69	2.78	818	549	2.22	27	18	2.56	95	63	-0.78	6	2	2.40	83	56
2009	3.63	3.27	816	371	5.09	27	17	3.63	95	49	0.90	6	2	2.98	93	42
2010	3.17	3.92	815	487	5.16	27	19	4.15	92	60	2.84	6	3	3.92	33	23
RATIO 48 ---- OPERATING MARGINS PER CONSUMER (\$)																
2006	67.47	56.57	818	346	84.19	27	17	51.03	99	37	38.29	6	3	68.68	110	56
2007	230.71	61.81	819	39	67.76	27	1	56.65	96	2	-28.93	6	1	60.63	167	6
2008	80.05	57.61	818	291	48.40	27	8	53.89	95	27	-14.52	6	1	54.23	83	29
2009	175.72	64.69	816	91	77.36	27	6	63.18	95	1	16.18	6	2	73.11	93	12
2010	159.15	81.23	815	136	91.26	27	4	79.34	92	11	85.58	6	1	96.10	33	9
RATIO 49 ---- NON-OPERATING MARGINS PER KWH SOLD (MILLS)																
2006	1.93	0.72	818	136	0.84	27	4	0.65	99	12	1.04	6	2	0.81	110	18
2007	1.98	0.75	819	122	1.04	27	7	0.68	96	10	2.97	6	5	0.76	167	27
2008	-0.63	0.59	817	780	0.74	27	26	0.50	95	93	0.39	6	5	0.46	83	79
2009	0.63	0.49	816	363	0.72	27	16	0.44	95	40	0.77	6	4	0.37	93	33
2010	4.18	0.50	815	24	0.64	27	2	0.44	92	3	1.21	6	1	0.51	33	3
RATIO 50 ---- NON-OPERATING MARGINS PER CONSUMER (\$)																
2006	83.25	13.85	818	45	14.83	27	1	11.32	99	3	38.31	6	1	16.31	110	8
2007	89.00	15.63	819	36	16.43	27	4	12.28	96	4	93.48	6	4	16.43	167	5
2008	-29.71	12.20	817	795	11.77	27	27	9.86	95	94	10.29	6	6	10.53	83	82
2009	30.60	10.41	816	158	11.87	27	6	9.20	95	16	23.58	6	3	7.38	93	16
2010	209.88	10.27	815	2	10.81	27	1	8.37	92	1	32.77	6	1	10.81	33	1

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 51 --- TOTAL MARGINS LESS ALLOCATIONS PER KWH SOLD (MILLS)																
2006	3.49	3.89	818	448	5.78	27	19	3.49	99	51	3.33	6	3	3.92	110	67
2007	7.12	4.01	819	154	5.75	27	11	3.26	96	7	2.48	6	2	3.63	167	26
2008	1.06	3.65	818	687	3.18	27	22	3.51	95	84	0.84	6	3	3.64	83	71
2009	4.26	4.08	816	391	4.85	27	17	4.15	95	47	3.50	6	3	3.93	93	41
2010	7.34	4.63	815	195	5.95	27	9	4.63	92	19	4.27	6	1	4.44	33	10
RATIO 52 --- TOTAL MARGINS LESS ALLOCATIONS PER CONSUMER (\$)																
2006	150.72	77.51	818	138	105.49	27	9	69.52	99	9	112.02	6	2	92.20	110	29
2007	319.71	82.39	819	27	111.58	27	1	66.08	96	1	52.30	6	1	79.21	167	3
2008	50.34	75.62	818	550	68.72	27	17	65.82	95	58	33.86	6	3	70.36	83	54
2009	206.31	80.44	816	82	87.82	27	2	74.98	95	2	72.86	6	1	76.05	93	12
2010	369.02	99.63	815	19	120.39	27	1	98.70	92	1	118.34	6	1	114.15	33	3
RATIO 53 --- INCOME (LOSS) FROM EQUITY INVESTMENTS PER CONSUMER (\$)																
2006	-16.16	0.09	243	213	1.16	7	5	-0.26	25	21	-16.16	3	2	1.91	27	24
2007	4.62	0.83	246	69	0.67	7	3	0.58	27	8	4.62	3	2	1.04	59	16
2008	-49.95	1.46	251	244	11.17	8	8	0.35	27	26	-36.70	3	3	0.35	33	32
2009	-39.60	1.39	247	239	1.83	8	7	1.23	23	22	-0.02	3	3	2.43	36	35
2010	136.24	1.76	244	3	3.62	8	1	0.43	20	1	1.61	3	1	1.57	12	1
RATIO 54 --- ASSOCIATED ORGANIZATION'S CAPITAL CREDITS PER KWH SOLD (MILLS)																
2006	0.16	1.32	768	693	0.83	27	24	1.25	89	85	0.19	6	5	1.61	104	97
2007	0.15	1.46	769	713	1.60	27	25	1.71	85	82	0.28	6	6	1.27	155	141
2008	0.28	2.04	769	691	3.21	27	24	2.04	85	82	0.60	6	5	1.44	78	68
2009	0.12	2.34	767	720	5.16	27	27	2.25	86	84	0.61	6	6	2.33	89	81
2010	0.22	2.54	767	710	4.35	27	26	2.94	83	80	0.71	6	6	2.33	31	31
RATIO 55 --- ASSOCIATED ORGANIZATION'S CAPITAL CREDITS PER CONSUMER (\$)																
2006	6.99	26.00	768	617	14.75	27	20	25.27	89	77	6.15	6	3	30.46	104	91
2007	6.94	29.99	769	642	24.65	27	22	32.05	85	76	7.79	6	4	28.69	155	125
2008	13.08	38.28	769	622	43.24	27	22	35.91	85	76	13.35	6	4	33.55	78	60
2009	5.89	43.39	767	670	68.62	27	25	37.57	86	83	16.50	6	6	39.58	89	74
2010	11.08	51.24	767	642	66.00	27	23	48.51	83	74	18.95	6	5	59.85	31	28
RATIO 56 --- TOTAL MARGINS PER KWH SOLD (MILLS)																
2006	3.65	5.71	818	591	6.58	27	21	5.89	99	70	3.51	6	3	6.31	110	88
2007	7.28	6.05	819	306	7.39	27	16	5.18	96	28	2.76	6	2	5.52	167	51
2008	1.34	6.13	818	754	6.12	27	24	5.41	95	86	1.02	6	3	5.08	83	77
2009	4.38	6.68	816	621	8.61	27	24	5.66	95	68	3.80	6	3	6.73	93	74
2010	7.56	7.20	815	378	9.00	27	19	7.16	92	43	5.21	6	1	8.16	33	20

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Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 57 ---- TOTAL MARGINS PER CONSUMER (\$)																
2006	157.72	112.20	818	228	122.43	27	10	106.70	99	15	122.05	6	3	129.49	110	43
2007	326.65	118.16	819	55	121.84	27	1	96.77	96	3	58.82	6	1	113.09	167	7
2008	63.42	122.96	818	650	120.09	27	21	112.99	95	73	41.55	6	3	109.60	83	64
2009	212.21	130.60	816	166	147.56	27	6	111.14	95	5	81.47	6	2	135.78	93	24
2010	380.10	150.51	815	43	164.27	27	1	136.39	92	1	138.99	6	1	172.65	33	6
RATIO 58 ---- A/R OVER 60 DAYS AS A % OF OPERATING REVENUE																
2006	0.02	0.20	808	761	0.23	25	23	0.19	99	95	0.04	6	5	0.18	109	97
2007	0.05	0.19	801	673	0.21	25	21	0.20	96	78	0.22	6	5	0.18	162	136
2008	0.07	0.17	806	625	0.18	26	20	0.17	94	71	0.16	6	5	0.19	83	66
2009	0.02	0.17	806	739	0.12	26	22	0.19	95	87	0.13	6	5	0.20	93	86
2010	0.02	0.17	802	754	0.16	26	25	0.18	92	87	0.21	6	6	0.17	33	31
RATIO 59 ---- AMOUNT WRITTEN OFF AS A % OF OPERATING REVENUE																
2006	0.08	0.18	791	636	0.10	27	19	0.24	99	95	0.05	6	3	0.14	102	67
2007	0.03	0.18	785	712	0.10	24	15	0.21	96	95	0.16	6	4	0.21	160	148
2008	0.03	0.18	791	731	0.15	25	20	0.21	94	93	0.14	6	6	0.19	81	77
2009	0.02	0.20	784	752	0.12	24	21	0.25	94	94	0.11	6	5	0.20	92	90
2010	0.03	0.18	779	731	0.13	26	24	0.20	89	89	0.14	6	6	0.17	31	29
SALES (RATIOS 60-76)																
RATIO 60 ---- TOTAL MWH SOLD PER MILE OF LINE																
2006	180.47	104.88	816	185	41.35	27	2	116.29	99	22	58.20	6	2	85.36	110	18
2007	188.85	109.02	819	186	49.46	27	3	117.64	96	21	130.46	6	3	114.24	167	37
2008	199.23	112.33	818	169	53.94	27	3	117.19	95	19	140.94	6	3	162.52	83	29
2009	204.70	110.39	816	152	53.45	27	3	111.73	95	15	143.44	6	3	125.09	93	19
2010	212.25	114.36	815	159	57.66	27	3	122.91	92	17	149.34	6	3	107.25	33	8
RATIO 61 ---- AVERAGE RESIDENTIAL USAGE KWH PER MONTH																
2006	983.02	1,167.95	817	620	983.02	27	14	1,174.26	99	79	956.39	6	2	1,112.85	110	75
2007	1,017.75	1,198.82	819	595	981.66	27	8	1,178.74	96	73	705.43	6	1	1,218.88	167	133
2008	1,011.85	1,191.15	818	602	967.89	27	7	1,168.69	95	71	793.43	6	1	1,277.77	83	74
2009	1,021.04	1,173.32	816	586	967.61	27	7	1,141.10	95	67	812.27	6	1	1,189.46	93	72
2010	1,087.90	1,239.39	815	568	1,043.30	27	7	1,203.29	92	61	881.54	6	1	1,146.30	33	18
RATIO 63 ---- AVERAGE IRRIGATION KWH USAGE PER MONTH																
2006	18,329.12	2,182.87	400	7	1,512.45	18	1	2,430.15	40	1	2,188.06	6	1	1,931.62	64	1
2007	17,532.92	2,125.51	399	10	1,295.39	18	1	2,157.66	41	1	1,688.20	6	1	2,639.78	75	2
2008	18,691.21	2,084.66	397	5	1,184.15	18	1	2,035.37	42	1	2,032.32	6	1	2,297.18	34	2
2009	15,962.29	1,951.34	397	10	1,278.80	18	1	2,089.37	42	1	1,876.78	6	1	2,123.41	41	2
2010	17,409.95	1,678.12	394	6	1,786.94	18	1	1,706.72	42	1	1,965.74	6	1	2,429.20	19	3

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Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 64 --- AVERAGE SMALL COMMERCIAL KWH USAGE PER MONTH																
2006	1,861.06	3,299.90	814	698	2,217.49	27	16	2,762.45	99	76	3,339.63	6	5	3,340.80	110	88
2007	1,853.20	3,333.33	817	707	2,153.96	27	18	2,747.88	96	73	2,587.96	6	5	3,512.13	167	149
2008	2,020.50	3,282.35	816	674	2,225.57	27	16	2,688.44	95	71	2,909.00	6	4	2,940.23	83	71
2009	2,024.08	3,228.63	813	669	2,106.24	27	15	2,686.69	95	73	2,412.19	6	4	3,117.94	93	78
2010	2,054.95	3,283.98	813	672	2,214.67	27	16	2,744.26	92	68	2,516.62	6	4	3,067.77	33	28
RATIO 65 --- AVERAGE LARGE COMMERCIAL KWH USAGE PER MONTH																
2006	1,219,115.08	487,916.67	673	145	239,527.78	16	2	445,246.38	89	18	832,180.73	4	2	361,105.16	88	17
2007	1,233,962.12	525,469.44	680	146	151,468.75	18	1	500,435.19	88	14	472,635.19	5	1	593,574.07	147	36
2008	1,175,608.70	505,968.75	684	164	156,222.22	19	2	554,897.22	88	20	146,472.22	5	1	555,725.00	70	12
2009	1,184,449.28	469,224.36	685	146	314,343.75	18	2	534,100.00	88	21	632,982.46	5	1	478,883.33	71	11
2010	1,210,847.83	464,600.00	683	151	300,541.67	19	3	479,125.00	85	20	732,972.22	5	1	683,305.56	27	11
RATIO 66 --- AVERAGE STREET & HIGHWAY LIGHTING KWH USAGE PER MONTH																
2006	4,750.00	1,554.61	584	99	2,183.33	19	3	2,334.33	62	18	4,347.70	5	2	1,696.57	72	14
2007	4,462.96	1,553.03	583	106	1,268.80	20	3	2,309.29	61	19	1,391.52	6	2	1,166.67	111	18
2008	4,462.96	1,483.33	582	101	1,483.74	20	2	2,036.46	61	18	1,728.46	6	1	1,307.61	63	8
2009	4,472.22	1,416.67	585	100	1,347.37	21	3	2,446.43	61	18	1,711.31	6	2	1,475.38	60	12
2010	3,659.09	1,405.75	584	135	1,174.48	21	2	1,768.19	62	22	1,565.78	6	1	2,027.78	21	7
RATIO 67 --- AVERAGE SALES FOR RESALE KWH USAGE PER MONTH																
2006	1,402,694.44	372,944.44	112	20	1,286,083.33	9	3	740,895.83	11	3	1,344,388.89	4	2	198,891.67	16	2
2007	1,439,694.44	416,722.22	110	21	1,408,541.67	9	3	779,625.00	9	2	1,424,118.06	4	2	420,777.78	21	6
2008	1,397,333.33	326,916.67	116	21	1,299,944.44	9	3	786,354.17	9	3	1,348,638.89	4	2	774,104.17	9	3
2009	1,376,583.33	331,583.33	120	20	1,282,111.11	8	3	587,555.56	9	3	1,323,708.33	4	2	621,781.25	12	2
2010	1,481,500.00	371,883.33	117	25	1,411,902.78	8	4	162,250.00	9	3	1,411,902.78	4	2	1,481,500.00	9	5
RATIO 69 --- RESIDENTIAL KWH SOLD PER TOTAL KWH SOLD (%)																
2006	8.68	61.39	817	809	61.80	27	27	62.91	99	99	15.73	6	6	56.05	110	109
2007	8.52	61.38	819	810	58.53	27	27	62.88	96	96	19.00	6	6	62.73	167	166
2008	7.88	61.30	818	808	55.90	27	27	61.53	95	95	18.95	6	6	62.50	83	83
2009	7.68	61.33	816	808	58.62	27	27	60.98	95	95	19.56	6	6	58.85	93	92
2010	7.83	61.83	815	809	58.49	27	27	62.69	92	92	20.06	6	6	49.80	33	32
RATIO 71 --- IRRIGATION KWH SOLD PER TOTAL KWH SOLD (%)																
2006	3.24	1.73	400	156	4.16	18	11	1.39	40	14	7.27	6	6	2.36	64	29
2007	4.80	1.37	399	125	3.12	18	4	1.18	41	6	4.18	6	2	0.95	75	17
2008	8.57	1.41	397	93	2.39	18	2	1.31	42	6	5.18	6	1	2.23	34	12
2009	11.64	1.18	398	78	3.13	18	2	1.42	42	5	4.95	6	1	4.98	41	14
2010	13.04	1.06	394	70	3.33	18	2	1.25	42	4	5.31	6	1	10.29	19	9

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Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 72 --- SMALL COMMERCIAL KWH SOLD PER TOTAL KWH SOLD (%)																
2006	34.79	17.38	814	70	26.49	27	8	15.63	99	4	35.36	6	4	17.51	110	16
2007	33.43	17.38	817	81	27.66	27	8	15.91	96	4	32.63	6	3	16.62	167	14
2008	34.44	17.27	816	77	28.43	27	9	15.77	95	4	33.02	6	3	17.39	83	6
2009	33.37	17.44	813	77	29.35	27	10	16.43	95	7	32.98	6	3	19.61	93	15
2010	32.63	17.32	813	81	29.18	27	9	15.91	92	6	32.45	6	3	21.35	33	6
RATIO 73 --- LARGE COMMERCIAL KWH SOLD PER TOTAL KWH SOLD (%)																
2006	45.70	13.40	673	54	14.76	16	1	13.82	89	5	35.88	4	1	14.19	88	11
2007	45.88	13.41	680	54	13.77	18	2	13.69	88	6	35.58	5	2	16.06	147	9
2008	42.46	14.05	684	69	15.34	19	2	14.93	88	9	35.02	5	2	13.46	70	7
2009	41.04	13.65	685	81	13.70	18	2	14.25	88	9	32.29	5	2	16.14	71	8
2010	40.05	13.96	683	87	14.66	19	2	14.68	85	11	33.14	5	2	15.70	27	5
RATIO 74 --- STREET & HIGHWAY LIGHTING KWH SOLD PER TOTAL KWH SOLD (%)																
2006	0.08	0.13	590	387	0.09	20	13	0.12	63	43	0.08	5	3	0.10	74	45
2007	0.07	0.13	588	407	0.18	21	16	0.12	61	44	0.34	6	6	0.12	111	73
2008	0.06	0.13	587	418	0.16	21	16	0.12	61	45	0.27	6	6	0.13	63	47
2009	0.06	0.13	589	425	0.15	22	16	0.13	61	45	0.27	6	6	0.15	61	49
2010	0.06	0.13	588	431	0.15	22	16	0.12	62	46	0.33	6	6	0.11	22	16
RATIO 75 --- SALES FOR RESALE PER TOTAL KWH SOLD (%)																
2006	7.51	3.92	114	37	13.92	9	9	5.98	11	5	20.74	4	4	2.12	16	6
2007	7.30	4.33	113	37	15.17	9	9	5.48	9	3	13.69	4	4	5.80	21	8
2008	6.58	3.41	117	37	10.46	9	9	5.36	9	3	9.52	4	4	6.58	9	5
2009	6.22	2.53	121	38	9.73	8	8	3.71	9	3	9.50	4	4	4.87	12	6
2010	6.39	3.33	119	37	9.10	8	8	1.06	9	2	9.26	4	4	6.39	9	5
CONTROLLABLE EXPENSES (RATIOS 77-87)																
RATIO 77 --- O & M EXPENSES PER TOTAL KWH SOLD (MILLS)																
2006	5.06	9.32	818	734	12.15	27	27	9.48	99	90	8.30	6	6	9.79	110	103
2007	4.50	9.36	819	761	12.29	27	27	9.84	96	93	9.09	6	6	9.27	167	157
2008	5.13	9.93	818	752	12.68	27	26	10.65	95	90	8.69	6	5	8.87	83	74
2009	4.88	10.36	816	769	12.76	27	26	10.86	95	91	7.60	6	5	9.52	93	88
2010	5.47	10.49	815	742	13.41	27	27	10.64	92	86	7.80	6	6	9.98	33	28
RATIO 78 --- O & M EXPENSES PER DOLLARS OF TUP (MILLS)																
2006	42.20	42.85	819	429	41.33	27	13	46.27	99	67	41.77	6	3	44.09	110	61
2007	35.18	43.44	820	609	42.46	27	23	47.56	96	83	44.17	6	5	44.10	167	133
2008	37.14	44.27	819	592	47.04	27	24	47.77	95	82	39.24	6	4	43.50	84	60
2009	34.30	43.26	817	641	43.55	27	24	46.40	95	89	34.84	6	5	39.70	93	60
2010	36.66	44.28	816	612	45.72	27	22	46.73	92	81	35.83	6	3	43.22	33	23

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Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 79 --- O & M EXPENSES PER CONSUMER (\$)																
2006	218.90	181.28	818	209	191.04	27	8	174.51	99	19	231.70	6	4	190.47	110	35
2007	201.80	190.57	819	335	202.58	27	15	183.83	96	30	203.97	6	4	191.55	167	71
2008	243.03	203.55	818	235	236.10	27	13	198.25	95	15	236.92	6	3	182.82	83	18
2009	236.24	207.68	816	263	221.92	27	11	202.67	95	26	211.05	6	2	195.11	93	26
2010	274.91	217.81	815	168	236.12	27	5	207.65	92	13	222.23	6	1	232.00	33	9
RATIO 80 --- CONSUMER ACCOUNTING EXPENSES PER TOTAL KWH SOLD (MILLS)																
2006	1.14	2.71	818	772	2.97	27	27	2.91	99	95	2.51	6	6	2.62	110	99
2007	0.96	2.70	818	789	2.94	27	27	2.85	96	94	2.45	6	6	2.68	167	162
2008	0.94	2.74	818	797	2.97	27	27	2.86	95	94	2.42	6	6	2.70	83	83
2009	0.98	2.86	816	790	3.08	27	27	3.15	95	93	1.92	6	6	2.83	93	90
2010	0.91	2.84	815	797	3.25	27	27	2.99	92	92	2.12	6	6	2.34	33	31
RATIO 81 --- CONSUMER ACCOUNTING EXPENSES PER CONSUMER (\$)																
2006	49.27	53.03	818	483	49.27	27	14	54.73	99	63	69.50	6	5	51.25	110	62
2007	43.15	53.45	818	624	51.50	27	20	53.53	96	70	64.50	6	6	53.02	167	131
2008	44.31	56.08	818	641	53.81	27	20	54.71	95	70	63.50	6	6	56.59	83	67
2009	47.26	57.61	816	586	54.78	27	16	56.61	95	65	51.02	6	4	57.82	93	66
2010	45.61	58.47	815	642	58.26	27	19	59.53	92	70	66.39	6	5	58.86	33	23
RATIO 82 --- CUSTOMER SALES AND SERVICE PER TOTAL KWH SOLD (MILLS)																
2006	0.68	0.82	807	469	0.90	25	20	0.73	97	51	0.89	6	5	0.69	108	55
2007	0.57	0.80	803	528	0.79	25	19	0.68	94	53	0.59	6	4	0.70	165	102
2008	0.49	0.86	806	575	0.84	25	19	0.67	92	60	0.57	6	4	0.88	83	60
2009	0.42	0.88	804	640	0.89	25	21	0.73	92	68	0.67	6	5	0.88	92	78
2010	0.44	0.88	801	618	0.89	25	21	0.67	90	64	0.62	6	5	0.89	33	24
RATIO 83 --- CUSTOMER SALES AND SERVICE PER CONSUMER (\$)																
2006	29.53	16.31	807	192	15.00	25	2	14.80	97	14	25.29	6	2	16.19	108	26
2007	25.67	16.41	803	246	13.67	25	1	14.63	94	20	16.08	6	1	15.44	165	50
2008	23.14	17.27	806	293	15.57	25	3	14.66	92	22	20.46	6	2	17.86	83	27
2009	20.28	17.32	804	354	15.68	25	8	15.22	92	34	21.52	6	4	18.03	92	37
2010	22.24	18.30	801	331	17.24	25	7	15.84	90	33	22.09	6	3	22.24	33	17
RATIO 84 --- A & G EXPENSES PER TOTAL KWH SOLD (MILLS)																
2006	3.18	5.32	818	677	7.21	27	27	4.76	99	87	6.20	6	6	5.97	110	98
2007	2.85	5.34	818	720	7.09	27	26	4.71	96	84	3.97	6	5	4.92	167	139
2008	2.99	5.47	818	706	7.03	27	26	5.21	95	82	3.90	6	5	4.85	83	67
2009	3.15	5.83	816	709	7.10	27	26	5.24	95	83	4.21	6	5	5.33	93	81
2010	3.24	5.78	815	678	7.44	27	26	5.30	92	76	4.36	6	5	5.89	33	29

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 85 ---- A & G EXPENSES PER CONSUMER (\$)																
2006	137.46	106.25	818	214	115.92	27	9	91.91	99	8	165.31	6	6	118.50	110	41
2007	127.88	108.30	818	297	114.32	27	10	89.65	96	13	121.19	6	3	98.64	167	50
2008	141.61	112.99	818	246	122.19	27	8	99.60	95	13	120.23	6	2	105.29	83	22
2009	152.37	115.92	816	230	117.15	27	9	104.73	95	11	132.60	6	3	117.29	93	29
2010	162.76	121.82	815	210	121.76	27	7	110.45	92	8	141.02	6	3	137.93	33	13
RATIO 86 ---- TOTAL CONTROLLABLE EXPENSES PER TOTAL KWH SOLD (MILLS) (SAME AS RATIO #103)																
2006	10.07	18.66	818	767	24.64	27	27	19.18	99	92	18.20	6	6	19.68	110	105
2007	8.88	19.04	819	789	24.04	27	27	19.36	96	94	16.79	6	6	17.67	167	161
2008	9.55	19.60	818	782	24.90	27	27	19.95	95	92	15.28	6	6	17.59	83	78
2009	9.42	20.27	816	785	23.54	27	27	20.42	95	92	13.87	6	6	18.51	93	90
2010	10.06	20.31	815	772	23.65	27	27	20.33	92	88	15.39	6	6	19.51	33	30
RATIO 87 ---- TOTAL CONTROLLABLE EXPENSES PER CONSUMER (\$) (SAME AS RATIO #104)																
2006	435.16	361.64	818	213	367.55	27	8	347.77	99	16	527.87	6	5	407.26	110	41
2007	398.50	372.38	819	338	395.12	27	13	350.18	96	27	396.81	6	3	362.24	167	66
2008	452.09	391.92	818	265	433.64	27	12	370.34	95	17	442.87	6	3	368.02	83	19
2009	456.15	403.19	816	274	412.37	27	8	394.41	95	19	413.50	6	2	395.18	93	26
2010	505.51	422.47	815	216	439.50	27	8	406.88	92	12	458.72	6	2	460.35	33	10
FIXED EXPENSES (RATIOS 88-102)																
RATIO 88 ---- POWER COST PER KWH PURCHASED (MILLS)																
2006	50.93	53.22	817	453	61.88	27	24	55.34	99	65	53.57	6	6	52.36	110	59
2007	48.92	55.43	819	521	60.10	27	23	56.74	96	68	60.11	6	6	54.32	167	110
2008	57.16	59.31	818	464	63.30	27	22	60.48	95	62	62.55	6	6	60.24	83	51
2009	55.98	61.10	814	472	63.67	27	22	63.79	95	61	56.64	6	5	63.97	93	62
2010	58.27	62.12	814	485	68.00	27	24	63.70	92	61	61.74	6	6	58.85	33	19
RATIO 89 ---- POWER COST PER TOTAL KWH SOLD (MILLS)																
2006	52.96	56.53	818	477	66.44	27	24	58.50	99	67	56.65	6	6	56.98	110	61
2007	50.91	58.82	819	528	64.18	27	24	60.91	96	70	61.43	6	6	57.78	167	109
2008	59.14	63.05	818	481	68.45	27	22	64.18	95	66	67.39	6	6	64.02	83	52
2009	57.93	64.59	816	513	69.26	27	24	67.93	95	67	60.11	6	6	68.37	93	64
2010	60.51	66.26	815	511	72.81	27	27	68.32	92	63	66.07	6	6	62.00	33	21
RATIO 90 ---- POWER COST AS A % OF REVENUE																
2006	74.06	61.44	819	79	58.47	27	1	62.98	99	10	64.19	6	1	60.57	110	12
2007	70.47	61.78	820	157	56.68	27	5	63.97	96	22	71.22	6	4	63.45	167	38
2008	76.93	63.10	819	50	58.08	27	2	64.35	95	7	75.07	6	2	65.47	84	8
2009	74.38	62.30	817	80	58.28	27	2	63.93	95	15	68.37	6	2	63.90	93	10
2010	74.61	62.54	816	80	59.35	27	1	63.43	92	14	68.55	6	1	59.33	33	5

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 91 --- LONG-TERM INTEREST COST PER TOTAL KWH SOLD (MILLS)																
2006	3.02	4.70	813	600	5.60	27	22	4.38	98	73	3.86	6	5	4.60	108	82
2007	2.74	4.87	813	639	5.68	27	23	4.74	94	74	3.79	6	5	4.43	166	126
2008	2.52	4.89	811	662	5.52	27	24	4.46	93	76	3.59	6	6	4.62	83	68
2009	2.73	5.16	809	649	6.57	27	24	4.85	92	71	4.21	6	5	4.88	92	74
2010	3.22	4.97	807	592	6.20	27	24	4.83	89	64	4.72	6	5	5.07	33	27
RATIO 92 --- LONG-TERM INTEREST COST AS A % OF TUP																
2006	2.52	2.17	813	224	1.75	27	4	2.27	98	34	1.90	6	2	2.10	108	24
2007	2.15	2.22	813	442	1.78	27	8	2.21	94	53	1.83	6	3	2.16	166	85
2008	1.83	2.22	811	549	1.80	27	13	2.30	93	61	1.69	6	3	2.35	83	59
2009	1.92	2.19	809	516	1.92	27	14	2.33	92	59	1.85	6	3	2.28	92	58
2010	2.16	2.12	807	383	2.08	27	10	2.23	89	49	2.12	6	3	2.11	33	15
RATIO 93 --- LONG-TERM INTEREST COST PER CONSUMER (\$)																
2006	130.76	90.40	813	154	88.80	27	5	84.25	98	13	117.57	6	2	95.65	108	27
2007	123.05	95.42	813	230	92.42	27	8	84.22	94	15	104.31	6	3	94.75	166	44
2008	119.49	99.79	811	280	96.15	27	9	88.78	93	23	103.19	6	3	99.16	83	32
2009	132.28	102.64	809	229	101.53	27	9	92.67	92	17	112.38	6	3	105.73	92	33
2010	162.02	102.90	807	115	109.77	27	7	97.37	89	9	132.56	6	2	132.65	33	9
RATIO 94 --- DEPRECIATION EXPENSE PER TOTAL KWH SOLD (MILLS)																
2006	3.81	6.14	818	736	8.54	27	27	6.06	99	89	5.87	6	6	6.28	110	100
2007	3.79	6.24	819	743	8.79	27	24	6.17	96	84	3.77	6	3	5.74	167	152
2008	3.66	6.42	818	761	8.54	27	27	6.29	95	85	5.44	6	6	5.85	83	82
2009	3.79	6.81	816	768	8.88	27	27	6.80	95	88	5.70	6	6	6.39	93	92
2010	3.84	6.88	815	765	8.34	27	27	6.80	92	82	5.78	6	6	6.75	33	31
RATIO 95 --- DEPRECIATION EXPENSE AS A % OF TUP																
2006	3.18	2.84	819	128	2.71	27	3	2.86	99	15	2.76	6	2	2.85	110	19
2007	2.96	2.83	820	271	2.58	27	4	2.85	96	33	1.79	6	1	2.85	167	60
2008	2.65	2.83	819	602	2.65	27	14	2.86	95	78	2.52	6	2	2.84	84	59
2009	2.66	2.86	817	596	2.60	27	12	2.91	95	76	2.44	6	2	2.86	93	73
2010	2.57	2.87	816	669	2.66	27	19	2.92	92	78	2.59	6	4	2.74	33	22
RATIO 96 --- DEPRECIATION EXPENSE PER CONSUMER (\$)																
2006	164.72	118.22	818	144	140.36	27	9	107.13	99	6	165.74	6	5	131.36	110	27
2007	169.95	122.76	819	144	122.58	27	5	108.00	96	4	97.52	6	2	115.40	167	24
2008	173.16	129.84	818	156	135.53	27	4	116.33	95	4	139.50	6	2	130.59	83	12
2009	183.43	135.05	816	148	139.24	27	4	121.32	95	5	143.58	6	2	138.24	93	24
2010	192.87	141.53	815	149	145.03	27	5	130.10	92	5	153.62	6	2	156.56	33	6

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 97 --- ACCUMULATIVE DEPRECIATION AS A % OF PLANT IN SERVICE																
2006	31.08	31.40	819	421	37.98	27	21	28.77	99	39	38.34	6	5	34.75	110	77
2007	30.84	31.12	820	420	35.86	27	21	29.13	96	40	36.27	6	5	30.84	167	84
2008	31.18	30.85	819	394	34.24	27	20	29.87	95	38	40.52	6	6	26.55	84	21
2009	29.63	30.88	817	465	32.66	27	20	30.02	95	52	38.30	6	6	28.61	93	38
2010	26.86	31.07	816	573	33.25	27	22	30.86	92	63	37.34	6	6	29.53	33	20
RATIO 98 --- TOTAL TAX EXPENSE PER TOTAL KWH SOLD (MILLS)																
2006	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2007	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2008	0.00	1.04	590	558	0.00	11	7	1.13	69	66	0.00	2	2	1.30	57	54
2009	0.01	1.00	595	532	0.01	11	6	1.12	71	66	0.01	3	3	1.28	67	60
2010	0.00	1.00	591	569	0.00	14	9	1.03	67	65	0.00	3	3	1.29	24	24
RATIO 99 --- TOTAL TAX EXPENSE AS A % OF TUP																
2006	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2007	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2008	0.00	0.43	591	554	0.00	11	6	0.50	69	66	0.00	2	2	0.45	58	54
2009	0.01	0.42	596	517	0.00	11	5	0.47	71	65	0.01	3	2	0.47	67	58
2010	0.00	0.41	592	568	0.00	14	9	0.48	67	65	0.00	3	3	0.50	24	24
RATIO 100 --- TOTAL TAX EXPENSE PER CONSUMER																
2006	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2007	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2008	0.05	20.10	590	551	0.04	11	5	22.40	69	65	0.04	2	1	22.51	57	53
2009	0.36	21.14	595	505	0.22	11	5	20.67	71	64	0.36	3	2	26.17	67	58
2010	0.01	22.00	591	563	0.01	14	6	20.96	67	65	0.04	3	3	31.25	24	24
RATIO 101 --- TOTAL FIXED EXPENSES PER TOTAL KWH SOLD (MILLS)																
2006	59.88	67.45	818	528	79.43	27	25	70.43	99	73	67.92	6	6	67.37	110	64
2007	58.23	69.51	819	586	77.22	27	25	72.24	96	77	72.20	6	6	68.22	167	119
2008	65.64	75.14	818	553	84.04	27	25	78.56	95	74	77.31	6	6	75.44	83	59
2009	64.84	78.14	816	605	82.86	27	24	80.08	95	82	71.75	6	6	80.42	93	73
2010	67.87	79.00	815	592	89.13	27	27	80.71	92	72	78.07	6	6	75.85	33	21
RATIO 102 --- TOTAL FIXED EXPENSES PER CONSUMER (\$)																
2006	2,588.48	1,293.88	818	50	1,367.74	27	2	1,227.74	99	4	1,976.52	6	2	1,281.02	110	10
2007	2,613.15	1,358.70	819	50	1,309.60	27	2	1,281.85	96	2	2,027.29	6	2	1,424.26	167	10
2008	3,107.50	1,464.63	818	46	1,419.51	27	1	1,368.86	95	1	2,369.87	6	1	1,565.76	83	1
2009	3,139.21	1,513.63	816	37	1,370.03	27	1	1,425.46	95	2	2,077.36	6	1	1,639.96	93	3
2010	3,410.82	1,601.50	815	35	1,563.92	27	1	1,496.02	92	2	2,350.08	6	1	1,654.75	33	2

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank

TOTAL EXPENSES (RATIOS 103-107)

RATIO 103 --- TOTAL OPERATING EXPENSES PER TOTAL KWH SOLD (MILLS)

2006	10.07	18.66	818	767	24.64	27	27	19.18	99	92	18.20	6	6	19.68	110	105
2007	8.88	19.04	819	789	24.04	27	27	19.36	96	94	16.79	6	6	17.67	167	161
2008	9.55	19.60	818	782	24.90	27	27	19.95	95	92	15.28	6	6	17.59	83	78
2009	9.42	20.27	816	785	23.54	27	27	20.42	95	92	13.87	6	6	18.51	93	90
2010	10.06	20.31	815	772	23.65	27	27	20.33	92	88	15.39	6	6	19.51	33	30

RATIO 104 --- TOTAL OPERATING EXPENSES PER CONSUMER (\$)

2006	435.16	361.64	818	213	367.55	27	8	347.77	99	16	527.87	6	5	407.26	110	41
2007	398.50	372.38	819	338	395.12	27	13	350.18	96	27	396.81	6	3	362.24	167	66
2008	452.09	391.92	818	265	433.64	27	12	370.34	95	17	442.87	6	3	368.02	83	19
2009	456.15	403.19	816	274	412.37	27	8	394.41	95	19	413.50	6	2	395.18	93	26
2010	505.51	422.47	815	216	439.50	27	8	406.88	92	12	458.72	6	2	460.35	33	10

RATIO 105 --- TOTAL COST OF SERVICE (MINUS POWER COSTS) PER TOTAL KWH SOLD (MILLS)

2006	16.99	30.71	818	761	38.56	27	27	31.70	99	93	27.87	6	6	30.67	110	103
2007	16.20	31.33	819	774	39.67	27	27	31.43	96	92	27.00	6	6	29.16	167	159
2008	16.04	32.38	818	780	39.62	27	27	32.37	95	91	25.14	6	6	29.41	83	80
2009	16.32	34.03	816	782	40.33	27	27	34.64	95	91	25.57	6	6	32.34	93	90
2010	17.42	33.59	815	773	40.30	27	27	33.38	92	87	28.46	6	6	34.32	33	30

RATIO 106 --- TOTAL COST OF ELECTRIC SERVICE PER TOTAL KWH SOLD (MILLS)

2006	69.94	85.45	818	651	102.86	27	26	89.44	99	82	84.28	6	6	83.70	110	86
2007	67.11	88.09	819	706	97.13	27	27	91.85	96	88	87.42	6	6	83.51	167	148
2008	75.19	94.48	818	677	103.76	27	27	96.14	95	85	92.05	6	6	90.48	83	68
2009	74.26	97.39	816	709	107.53	27	26	101.07	95	88	85.09	6	6	97.14	93	81
2010	77.93	98.46	815	704	109.29	27	27	98.94	92	86	94.00	6	6	94.47	33	27

RATIO 107 --- TOTAL COST OF ELECTRIC SERVICE PER CONSUMER (\$)

2006	3,023.64	1,654.67	818	53	1,729.50	27	2	1,575.16	99	4	2,559.99	6	2	1,669.99	110	11
2007	3,011.65	1,723.68	819	59	1,748.98	27	3	1,637.87	96	2	2,480.22	6	2	1,758.26	167	11
2008	3,559.59	1,865.47	818	50	1,878.61	27	1	1,797.41	95	1	2,790.29	6	1	1,921.52	83	1
2009	3,595.37	1,912.47	816	44	1,737.47	27	1	1,843.07	95	2	2,489.67	6	1	1,970.93	93	3
2010	3,916.34	2,023.01	815	38	1,982.02	27	1	1,922.35	92	2	2,808.80	6	1	2,205.85	33	2

EMPLOYEES (RATIOS 108-113)

RATIO 108 --- AVERAGE WAGE RATE PER HOUR (\$)

2006	28.39	24.84	814	164	23.47	27	3	24.34	98	22	26.75	6	3	24.62	109	24
2007	25.82	26.16	817	440	25.97	27	15	25.45	96	44	28.06	6	6	26.04	166	90
2008	26.76	27.16	817	448	26.46	27	9	26.89	95	50	26.63	6	3	27.24	83	47
2009	30.30	28.44	814	265	27.85	27	8	27.62	95	27	30.73	6	4	28.87	93	29
2010	32.95	29.37	812	161	29.25	26	6	28.11	92	14	29.83	6	2	31.67	33	11

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 109 --- TOTAL WAGES PER TOTAL KWH SOLD (MILLS)																
2006	5.38	9.95	815	747	14.38	27	27	9.47	98	92	13.14	6	6	10.57	110	103
2007	5.50	10.14	817	753	15.15	27	27	9.95	96	91	9.02	6	6	9.65	166	152
2008	5.15	10.44	817	774	14.37	27	27	10.32	95	92	8.96	6	6	8.97	83	78
2009	5.31	10.93	815	775	15.74	27	27	10.75	95	90	9.56	6	6	10.13	93	90
2010	5.28	10.59	813	766	15.05	26	26	10.01	92	89	10.83	6	6	12.62	33	31
RATIO 110 --- TOTAL WAGES PER CONSUMER (\$)																
2006	232.67	196.57	815	275	232.78	27	15	172.79	98	16	336.72	6	6	217.10	110	54
2007	246.82	205.69	817	266	252.09	27	15	176.91	96	14	262.12	6	4	194.70	166	47
2008	243.75	214.65	817	299	253.67	27	16	189.41	95	18	253.85	6	4	191.29	83	26
2009	257.02	218.38	815	286	271.39	27	18	190.76	95	20	265.88	6	4	218.57	93	36
2010	265.49	220.57	813	280	279.44	26	18	193.85	92	13	272.29	6	4	277.11	33	21
RATIO 111 --- OVERTIME HOURS/TOTAL HOURS (%)																
2006	6.88	4.98	811	167	4.13	27	1	5.90	97	33	4.29	6	1	4.84	109	20
2007	11.54	5.30	817	26	8.05	27	5	5.88	96	4	11.43	6	3	5.23	167	6
2008	8.45	5.25	816	100	5.70	27	6	5.83	95	17	6.25	6	1	5.51	83	8
2009	7.42	4.94	814	152	5.37	27	6	5.64	95	23	4.72	6	1	4.85	93	12
2010	6.34	4.61	813	158	3.85	27	7	4.89	92	19	3.75	6	1	5.27	33	14
RATIO 112 --- CAPITALIZED PAYROLL / TOTAL PAYROLL (%)																
2006	22.21	23.67	814	484	26.26	27	23	24.60	98	70	23.52	6	5	22.51	110	58
2007	36.64	23.58	816	51	31.48	27	10	24.92	96	11	32.11	6	3	24.52	166	10
2008	30.25	22.83	814	140	30.08	27	13	24.40	95	22	28.58	6	2	23.58	83	19
2009	31.26	22.12	812	119	31.48	27	16	23.34	95	20	31.37	6	4	22.06	92	14
2010	29.23	22.47	812	149	35.21	26	18	23.06	92	19	26.28	6	3	24.58	33	9
RATIO 113 --- AVERAGE CONSUMERS PER EMPLOYEE																
2006	277.68	276.41	815	401	224.64	27	5	305.99	98	64	163.52	6	1	243.63	110	37
2007	272.78	282.23	819	436	226.50	27	8	306.00	96	72	239.67	6	2	290.39	167	97
2008	256.21	286.08	818	495	227.07	27	10	308.45	95	77	246.17	6	3	318.77	83	60
2009	269.72	287.19	816	460	217.11	27	8	308.69	95	73	244.31	6	2	295.30	93	53
2010	259.47	291.20	815	495	225.08	27	10	309.77	92	76	251.81	6	3	251.73	33	13

GROWTH (RATIOS 114-121)

RATIO 114 --- ANNUAL GROWTH IN KWH SOLD (%)																
2006	5.16	1.78	817	196	4.43	27	13	1.53	99	22	5.86	6	5	1.67	110	31
2007	5.62	3.70	815	230	4.96	27	12	3.15	93	19	73.33	6	6	3.59	167	45
2008	7.63	1.22	817	112	2.60	27	7	1.00	95	16	12.39	6	6	1.33	83	14
2009	4.25	-1.06	816	104	-0.31	27	3	-1.59	95	8	-0.65	6	1	-0.87	93	18
2010	4.76	4.80	813	412	6.59	27	19	5.38	92	51	4.93	6	4	5.65	33	19

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 115 --- ANNUAL GROWTH IN NUMBER OF CONSUMERS (%)																
2006	2.98	1.51	817	133	1.44	27	7	1.72	99	15	2.38	6	3	1.18	110	5
2007	1.74	1.35	815	295	1.74	27	14	1.35	93	31	88.29	6	6	1.24	167	43
2008	2.02	0.99	817	139	0.85	27	8	0.90	95	15	1.81	6	3	1.39	83	23
2009	1.93	0.47	816	56	1.00	27	7	0.41	95	7	1.31	6	2	0.71	93	10
2010	0.93	0.37	813	181	0.47	27	7	0.27	92	14	0.99	6	4	0.70	33	12
RATIO 116 --- ANNUAL GROWTH IN TUP DOLLARS (%)																
2006	-1.97	5.60	818	813	5.55	27	27	5.93	99	99	6.31	6	6	3.95	110	110
2007	12.52	5.72	816	53	7.67	27	10	5.74	93	3	70.27	6	6	5.95	167	5
2008	16.40	5.23	818	16	5.26	27	3	5.16	95	2	8.56	6	2	6.33	84	1
2009	7.28	4.40	817	117	4.89	27	9	4.41	95	17	6.09	6	3	5.62	93	25
2010	9.89	3.92	814	52	4.37	27	4	3.95	92	6	5.32	6	2	5.16	33	7
RATIO 117 --- CONST. W.I.P. TO PLANT ADDITIONS (%)																
2006	17.35	24.72	793	504	18.65	26	14	21.97	97	54	24.32	6	4	18.64	105	59
2007	114.76	25.77	809	75	37.16	27	6	19.12	95	4	33.27	6	1	29.65	165	16
2008	168.54	27.04	810	45	15.59	26	1	21.24	94	4	45.67	6	1	36.01	83	5
2009	223.51	27.25	808	33	51.90	25	2	25.29	94	6	56.24	6	2	32.77	93	5
2010	245.64	30.09	808	30	35.10	27	4	23.00	91	2	72.68	6	1	37.22	33	4
RATIO 118 --- NET NEW SERVICES TO TOTAL SERVICES (%)																
2006	2.31	1.58	816	225	1.05	27	7	1.79	99	32	1.96	6	3	1.19	110	19
2007	1.67	1.36	817	307	1.06	27	8	1.55	96	45	1.18	6	2	1.42	167	61
2008	2.29	1.06	816	72	1.04	27	6	1.04	95	10	1.03	6	2	1.39	83	9
2009	1.51	0.66	813	110	0.50	27	5	0.73	95	12	0.73	6	1	0.85	93	24
2010	1.46	0.56	811	91	0.37	27	4	0.54	92	12	0.67	6	1	0.76	33	10
RATIO 119 --- ANNUAL GROWTH IN TOTAL CAPITALIZATION (%)																
2006	1.94	5.12	818	643	5.89	27	20	5.47	99	80	0.72	6	3	4.11	110	82
2007	2.68	5.48	816	589	6.70	27	22	5.15	93	65	39.18	6	6	4.79	167	122
2008	8.95	4.61	818	209	7.60	27	12	4.30	95	23	8.89	6	3	6.67	84	33
2009	2.17	4.11	817	584	5.51	27	23	3.78	95	65	7.21	6	6	4.95	93	74
2010	19.02	4.05	814	26	4.08	27	3	3.69	92	3	9.89	6	2	9.23	33	5
RATIO 120 --- 2YR. COMPOUND GROWTH IN TOTAL CAPITALIZATION (%)																
2006	12.15	5.60	814	58	7.00	27	6	5.13	97	7	5.55	6	2	4.09	110	2
2007	2.31	5.53	817	696	6.86	27	27	5.60	93	81	20.10	6	6	5.10	167	148
2008	5.77	5.62	814	397	6.57	27	17	5.53	92	43	35.75	6	6	7.62	84	61
2009	5.51	5.05	816	370	6.79	27	19	5.02	95	43	7.46	6	6	7.59	93	63
2010	10.28	4.54	814	93	6.69	27	7	4.34	92	11	8.36	6	2	7.67	33	11

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 121 --- 5 YR. COMPOUND GROWTH IN TOTAL CAPITALIZATION (%)																
2006	6.62	4.93	810	222	4.85	26	9	4.72	97	27	5.88	6	3	3.42	110	10
2007	5.34	5.20	808	385	6.85	27	17	5.14	92	43	12.97	6	6	4.88	167	68
2008	7.11	5.64	810	224	7.01	27	13	5.22	91	23	16.37	6	6	7.25	84	47
2009	7.53	5.65	808	211	8.57	27	17	5.62	90	21	17.49	6	6	7.68	93	53
2010	6.76	5.36	809	255	7.28	27	15	5.49	89	26	16.55	6	6	8.70	33	26
PLANT (RATIOS 122-145)																
RATIO 122 --- TUP INVESTMENTS PER TOTAL KWH SOLD (CENTS)																
2006	12.00	21.62	818	760	30.64	27	27	21.50	99	91	21.33	6	6	21.97	110	103
2007	12.78	22.02	819	755	31.01	27	27	20.67	96	86	19.57	6	6	20.34	167	153
2008	13.82	22.71	818	739	31.01	27	27	21.32	95	83	18.66	6	6	19.91	83	79
2009	14.23	23.89	816	743	32.08	27	27	23.02	95	87	19.44	6	6	21.97	93	89
2010	14.92	24.10	815	716	31.56	27	27	22.91	92	76	19.12	6	6	25.33	33	30
RATIO 123 --- TUP INVESTMENT PER CONSUMER (\$)																
2006	5,186.66	4,114.77	818	233	4,986.01	27	13	3,799.05	99	12	6,064.72	6	6	4,461.38	110	45
2007	5,735.90	4,303.16	819	190	4,976.95	27	9	3,786.24	96	8	5,641.92	6	3	4,015.59	167	37
2008	6,544.34	4,473.15	818	131	5,029.48	27	3	4,007.86	95	4	5,526.36	6	1	4,383.49	83	12
2009	6,887.82	4,676.44	816	130	5,407.91	27	4	4,190.44	95	7	5,964.85	6	1	4,703.70	93	23
2010	7,499.29	4,854.04	815	106	5,492.58	27	3	4,390.59	92	3	6,048.76	6	1	5,655.06	33	9
RATIO 124 --- TUP INVESTMENT PER MILE OF LINE (\$)																
2006	21,652.52	22,567.64	816	441	12,743.99	27	5	23,443.77	99	70	12,445.80	6	2	17,245.69	110	38
2007	24,137.66	23,941.64	819	406	14,139.97	27	6	24,350.27	96	50	19,629.14	6	3	23,580.37	167	78
2008	27,540.29	25,113.04	818	360	15,108.75	27	6	25,558.97	95	40	22,598.03	6	3	33,916.99	83	55
2009	29,120.41	26,205.55	816	355	16,250.47	27	6	26,699.25	95	39	23,774.92	6	3	31,391.24	93	51
2010	31,673.27	27,285.65	815	318	17,807.44	27	6	27,612.66	92	31	25,367.38	6	3	34,425.56	33	18
RATIO 125 --- AVERAGE CONSUMERS PER MILE																
2006	4.17	5.84	816	549	2.84	27	6	6.21	99	86	1.96	6	2	4.20	110	56
2007	4.21	5.93	819	556	3.02	27	7	6.25	96	84	3.88	6	3	6.12	167	123
2008	4.21	5.93	818	558	3.12	27	7	6.31	95	85	3.86	6	3	7.86	83	66
2009	4.23	5.93	816	553	3.16	27	7	6.27	95	83	3.88	6	3	6.75	93	64
2010	4.22	5.94	815	558	3.16	27	7	6.22	92	81	3.88	6	3	5.84	33	20
RATIO 126 --- DISTRIBUTION PLANT PER TOTAL KWH SOLD (MILLS)																
2006	98.35	179.56	818	763	255.91	27	27	179.49	99	91	175.43	6	6	188.10	110	103
2007	97.02	183.51	819	770	249.09	27	27	182.72	96	88	126.86	6	6	175.25	167	162
2008	98.02	189.62	818	771	259.20	27	26	190.94	95	88	138.22	6	5	166.42	83	81
2009	101.19	199.69	816	777	243.48	27	27	201.89	95	90	146.98	6	6	176.35	93	91
2010	104.17	201.11	815	767	245.06	27	27	200.84	92	86	141.13	6	6	187.41	33	29

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 127 --- DISTRIBUTION PLANT PER CONSUMER (\$)																
2006	4,251.55	3,452.99	818	214	4,035.05	27	12	3,197.55	99	10	5,050.18	6	6	3,699.81	110	44
2007	4,354.06	3,572.95	819	219	3,956.00	27	9	3,244.18	96	9	4,275.84	6	3	3,420.76	167	39
2008	4,640.38	3,719.00	818	211	4,199.48	27	9	3,495.57	95	8	4,221.88	6	3	3,669.31	83	18
2009	4,899.39	3,894.36	816	197	4,298.33	27	8	3,631.23	95	7	4,380.09	6	3	3,826.79	93	26
2010	5,234.78	4,029.11	815	172	4,369.94	27	6	3,776.93	92	5	4,230.86	6	2	4,401.95	33	10
RATIO 128 --- DISTRIBUTION PLANT PER EMPLOYEE (\$)																
2006	1,180,564.71	972,132.93	815	168	814,346.42	27	3	982,808.80	98	18	790,103.50	6	1	926,905.02	110	19
2007	1,187,681.86	1,018,721.25	819	206	884,235.67	27	5	1,006,673.81	96	22	901,304.36	6	1	1,040,351.84	167	48
2008	1,188,894.14	1,080,619.33	818	268	973,065.36	27	5	1,068,933.25	95	28	962,849.79	6	2	1,138,930.80	83	38
2009	1,321,469.93	1,141,956.32	816	202	987,385.83	27	4	1,115,218.65	95	17	1,038,591.43	6	1	1,124,668.07	93	21
2010	1,358,262.30	1,198,286.18	815	230	1,027,159.89	27	4	1,161,595.03	92	20	1,174,140.06	6	1	1,087,831.15	33	12
RATIO 129 --- GENERAL PLANT PER TOTAL KWH SOLD (MILLS)																
2006	6.01	14.61	817	766	18.39	27	27	12.94	99	96	15.68	6	6	15.04	110	107
2007	6.03	14.59	819	774	18.13	27	27	12.97	96	93	9.61	6	6	13.98	167	155
2008	5.77	14.65	818	782	17.83	27	27	14.02	95	92	11.63	6	6	12.75	83	78
2009	5.77	15.68	816	786	20.66	27	27	15.33	95	93	13.18	6	6	15.76	93	90
2010	5.95	15.59	815	783	20.90	27	27	14.27	92	88	13.15	6	6	16.93	33	32
RATIO 130 --- GENERAL PLANT PER CONSUMER (\$)																
2006	259.66	281.41	817	465	316.86	27	19	246.55	99	44	408.81	6	6	313.22	110	73
2007	270.40	287.56	819	458	281.87	27	16	241.20	96	38	262.19	6	3	266.35	167	82
2008	273.40	301.11	818	475	322.17	27	19	249.38	95	44	305.41	6	4	265.03	83	39
2009	279.27	314.82	816	483	360.89	27	21	259.58	95	44	329.71	6	4	319.36	93	56
2010	299.22	330.11	815	461	383.18	27	19	279.76	92	43	360.23	6	4	360.41	33	25
RATIO 131 --- GENERAL PLANT PER EMPLOYEE (\$)																
2006	72,101.04	77,029.18	814	474	67,648.77	27	12	76,327.52	98	57	64,629.77	6	2	70,412.71	110	52
2007	73,759.33	80,789.70	819	498	69,971.92	27	12	76,100.64	96	53	68,845.58	6	2	78,956.89	167	95
2008	70,045.84	83,541.52	818	577	71,586.07	27	15	80,083.18	95	59	69,154.07	6	3	84,107.94	83	61
2009	75,323.80	87,912.69	816	557	77,010.50	27	16	84,463.62	95	58	78,272.64	6	5	93,052.99	93	67
2010	77,639.22	92,827.10	815	586	80,170.22	27	18	92,860.39	92	60	88,491.31	6	5	99,514.36	33	25
RATIO 132 --- HEADQUARTERS PLANT PER TOTAL KWH SOLD (MILLS)																
2006	9.71	6.97	765	217	6.43	26	9	6.40	95	28	8.75	6	3	5.92	101	20
2007	9.19	6.92	770	240	6.06	25	7	6.62	93	29	6.71	5	1	6.13	164	40
2008	8.60	7.27	770	306	7.36	26	12	6.86	92	36	7.33	5	1	9.37	77	44
2009	8.24	7.87	767	355	7.40	25	12	7.68	92	41	7.40	5	2	9.72	86	53
2010	7.88	7.87	764	381	6.98	25	12	7.88	89	45	6.97	5	2	8.89	31	17

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Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 133 --- HEADQUARTERS PLANT PER CONSUMER (\$)																
2006	419.58	137.14	765	32	110.59	26	1	134.25	95	3	275.18	6	1	130.22	101	5
2007	412.39	140.40	770	41	108.41	25	1	126.24	93	3	113.73	5	1	132.82	164	6
2008	407.36	149.13	770	52	127.38	26	2	132.04	92	3	136.05	5	1	189.21	77	10
2009	398.85	159.95	767	68	135.19	25	2	146.01	92	4	181.20	5	1	198.34	86	16
2010	396.05	167.47	764	82	138.91	25	2	154.65	89	8	193.50	5	1	210.92	31	9
RATIO 134 --- HEADQUARTERS PLANT PER EMPLOYEE (\$)																
2006	116,508.00	36,798.76	763	20	23,105.22	26	1	40,132.01	94	4	37,258.78	6	1	29,514.18	101	1
2007	112,490.48	37,886.03	770	27	22,119.40	25	1	39,073.07	93	5	32,158.44	5	1	37,565.48	164	5
2008	104,368.37	40,465.37	770	60	26,278.72	26	3	40,736.94	92	5	31,890.57	5	1	60,049.37	77	12
2009	107,577.39	43,663.11	767	64	27,913.38	25	3	42,203.69	92	6	38,105.73	5	1	57,379.66	86	13
2010	102,761.33	46,505.67	764	96	28,804.00	25	3	45,941.45	89	12	40,382.54	5	1	56,294.57	31	8
RATIO 135 --- TRANSMISSION PLANT PER TOTAL KWH SOLD (MILLS)																
2006	4.34	11.14	416	301	9.02	23	18	5.65	43	26	6.28	5	4	15.10	56	44
2007	4.12	10.99	417	306	10.22	24	21	6.11	39	24	11.20	6	6	8.08	79	54
2008	5.98	11.53	413	275	10.84	24	18	5.96	38	19	17.55	6	6	9.80	40	24
2009	3.67	12.02	413	315	11.10	24	21	5.83	38	25	19.31	6	6	14.01	49	36
2010	3.57	13.07	410	308	10.16	24	20	8.17	37	25	19.87	6	6	12.16	22	14
RATIO 136 --- TRANSMISSION PLANT PER CONSUMER (\$)																
2006	187.51	216.28	416	228	182.07	23	10	142.44	43	17	205.85	5	4	343.60	56	35
2007	184.86	217.11	417	233	180.12	24	10	162.42	39	18	343.94	6	4	157.33	79	36
2008	283.24	230.14	413	186	210.97	24	11	172.68	38	14	586.74	6	5	221.98	40	18
2009	177.76	234.16	413	252	179.77	24	14	182.45	38	20	623.83	6	6	277.50	49	33
2010	179.53	248.28	410	250	180.21	24	14	212.20	37	20	654.16	6	6	292.25	22	13
RATIO 137 --- TRANSMISSION PLANT PER EMPLOYEE (\$)																
2006	52,066.82	58,766.67	416	226	44,771.32	23	9	39,105.10	43	17	50,391.06	5	2	65,871.42	56	35
2007	50,426.67	61,530.42	417	233	45,443.47	24	11	44,938.86	39	18	75,855.31	6	4	44,300.30	79	35
2008	72,568.65	67,788.18	413	193	57,272.20	24	9	48,742.60	38	14	146,035.38	6	5	55,226.58	40	19
2009	47,946.66	68,926.21	413	253	49,149.75	24	13	45,465.83	38	19	153,963.99	6	6	71,579.60	49	33
2010	46,582.33	71,810.98	410	256	49,474.64	24	13	60,336.64	37	20	164,952.34	6	6	64,353.63	22	13
RATIO 138 --- IDLE SERVICES TO TOTAL SERVICE (%)																
2006	5.40	7.88	794	515	7.73	27	18	9.92	97	78	5.87	6	5	8.68	106	68
2007	5.97	7.77	797	486	6.91	27	17	10.05	95	70	6.15	6	4	8.26	164	104
2008	5.58	7.67	797	517	6.92	27	18	9.91	94	70	5.93	6	4	7.20	80	49
2009	6.21	7.86	796	480	6.57	27	16	10.62	94	68	6.14	6	3	6.37	91	48
2010	6.58	8.12	793	464	7.23	27	15	10.25	90	65	5.65	6	2	8.96	32	19

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 139 --- LINE LOSS (%)																
2006	3.66	5.86	817	712	7.33	27	23	6.10	99	87	5.87	6	5	6.71	110	99
2007	3.72	6.03	819	730	7.41	27	25	6.24	96	88	4.47	6	4	5.96	167	148
2008	3.20	6.04	818	756	7.67	27	26	6.05	95	88	5.82	6	5	5.48	83	78
2009	3.21	5.96	814	739	7.54	27	27	6.20	95	89	6.17	6	6	5.82	93	86
2010	3.54	5.98	814	724	7.36	27	26	6.27	92	84	6.28	6	6	5.97	33	26
RATIO 140 --- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - POWER SUPPLIER																
2006	15.99	0.26	819	7	1.27	27	1	0.22	99	2	0.82	6	1	0.29	110	3
2007	0.72	0.25	820	241	1.67	27	19	0.33	96	30	0.14	6	1	0.23	167	53
2008	3.34	16.39	819	571	78.60	27	25	22.10	95	70	9.60	6	5	8.38	84	53
2009	4.09	14.80	817	554	84.81	27	23	14.80	95	66	15.19	6	5	9.60	93	59
2010	37.01	15.76	816	247	28.30	27	13	12.97	92	27	11.06	6	1	5.40	33	7
RATIO 141 --- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - EXTREME STORM																
2006	32.47	0.21	819	12	0.20	27	3	0.46	99	2	20.99	6	3	0.40	110	2
2007	86.72	0.40	820	20	17.60	27	5	0.51	96	2	13.93	6	2	0.59	167	8
2008	13.81	28.20	819	480	33.60	27	15	71.40	95	71	7.43	6	3	20.85	84	52
2009	0.00	19.83	817	639	95.40	27	24	31.80	95	80	0.00	6	4	12.06	93	71
2010	0.00	18.79	816	658	12.00	27	24	11.82	92	76	6.00	6	5	27.47	33	28
RATIO 142 --- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - PREARRANGED																
2006	0.13	0.02	819	203	0.02	27	10	0.02	99	26	0.19	6	4	0.02	110	28
2007	0.04	0.03	820	373	0.06	27	15	0.03	96	45	0.03	6	3	0.03	167	78
2008	14.08	2.34	819	142	2.04	27	6	1.80	95	15	7.64	6	3	2.11	84	10
2009	5.69	2.59	817	296	3.48	27	13	2.52	95	31	3.74	6	3	1.88	93	32
2010	5.53	2.23	816	260	6.00	27	15	3.18	92	28	9.45	6	4	4.00	33	15
RATIO 143 --- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - ALL OTHER																
2006	2.00	1.63	819	327	1.44	27	11	1.77	99	45	1.73	6	3	1.53	110	38
2007	3.49	1.62	820	123	2.15	27	4	1.91	96	18	3.46	6	3	1.64	167	30
2008	92.43	99.36	819	446	158.64	27	19	102.30	95	56	106.45	6	4	96.21	84	45
2009	61.72	95.40	817	571	91.80	27	21	100.02	95	69	69.22	6	5	95.40	93	67
2010	64.78	97.35	816	589	90.74	27	22	97.14	92	70	73.94	6	4	110.03	33	23
RATIO 144 --- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - TOTAL																
2006	50.59	3.00	819	11	3.76	27	3	3.29	99	2	32.54	6	3	3.32	110	3
2007	90.97	3.37	820	21	21.83	27	6	3.76	96	2	16.07	6	2	3.53	167	9
2008	123.66	201.96	819	588	333.00	27	25	285.00	95	75	128.83	6	4	170.65	84	62
2009	71.50	196.20	817	703	406.06	27	26	187.20	95	82	104.32	6	6	165.61	93	80
2010	107.31	188.64	816	619	228.60	27	23	177.40	92	70	148.46	6	5	190.20	33	25

2010 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2005-2010)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 145 --- AVG. SERVICE AVAILABILITY INDEX (ASAI) - TOTAL (%)																
2006	99.42	99.97	819	809	99.96	27	25	99.96	99	98	99.63	6	4	99.96	110	108
2007	98.96	99.96	820	800	99.75	27	22	99.96	96	95	99.82	6	5	99.96	167	159
2008	99.98	99.96	819	232	99.94	27	3	99.95	95	21	99.98	6	3	99.97	84	23
2009	99.99	99.96	817	114	99.92	27	2	99.96	95	14	99.98	6	1	99.97	93	14
2010	99.98	99.96	816	198	99.96	27	5	99.97	92	23	99.97	6	2	99.96	33	9

CERTIFICATE OF SERVICE

12-MKEE-380-RTS

I, the undersigned, hereby certify that a true and correct copy of the above and foregoing Direct Testimony was served via electronic service this 20th day of April, 2012, to the following:

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